88/1038/NP

NEW WORK ITEM PROPOSAL (NP)

PROPOSER:	DATE OF PROPOSAL:
United States of America	**2024-06-20**
DATE OF CIRCULATION:	CLOSING DATE FOR VOTING:
2024-06-21	**2024-08-16**

IEC TC 88 : WIND ENERGY GENERATION SYSTEMS

SECRETARIAT:	SECRETARY:
Denmark	Mrs Christine Weibøl Bertelsen
NEED FOR IEC COORDINATION:	PROPOSED HORIZONTAL STANDARD: ☐ Other TC/SCs are requested to indicate their interest, if any, in this NP to the TC/SC secretary

FUNCTIONS CONCERNED:

☐ EMC ☒ ENVIRONMENT ☒ QUALITY ASSURANCE ☐ SAFETY

TITLE OF PROPOSAL:

Wind energy generation systems - Part 15-2: Framework for assessment and reporting of the wind resource and energy yield

☒ STANDARD ☐ TECHNICAL SPECIFICATION ☐ PUBLICLY AVAILABLE SPECIFICATION

PROPOSED PROJECT NUMBER: 61400-15-2

SCOPE

(AS DEFINED IN ISO/IEC DIRECTIVES, PART 2, 14):

The scope of this standard is the assessment and reporting of site-specific wind conditions and energy yield for wind power plants. This includes the following key scope components:

- all measurement, analysis and evaluation steps including data analysis, modeling, loss assessment and net energy production estimation for wind power stations as required to make the results reproducible and traceable to national standards;

- definition of documentation and reporting requirements to make the results traceable to national standards;

- definition of a digital exchange format for energy yield reporting to facilitate efficient information exchange;

• a standardized approach to the uncertainty quantification of a site-specific energy yield assessment (EYA).

The standard will include in its scope the assessment of site-specific wind conditions and related parameters to determine the potential energy at a site.

Specifically, the suitability of methods already in use by the wind industry for the stated purpose should be discussed and agreed. These methods include but are not limited to data processing, long term correction such as MCP (Measure Correlate Predict), power curve modeling, wake modeling, site optimization and use of reanalysis data or any other currently applied methods known to the experts of the project team. Areas where scientific consensus in lacking will be included as informative annexes.

Scope limitations:

According to IEC 61400-1 the site-specific conditions can be broken down into wind conditions, other environmental conditions, soil conditions and electrical conditions. Furthermore, each condition can be subdivided into normal and extreme conditions as far as they affect the wind flow. All of these site conditions other than site specific wind conditions and related documents are out of scope for this standard.

PURPOSE AND JUSTIFICATION

INCLUDING THE MARKET RELEVANCE AND WHETHER IT IS PROPOSED TO BE A HORIZONTAL STANDARD.

MARKET RELEVANCE SHOULD BE ADDRESSED BY INDICATING THE NEED FOR THE CORRESPONDING STANDARDS WORK AND ITS GLOBAL RELEVANCE (SEE ISO/IEC DIRECTIVES, PART 1 ANNEX C)

IF PROPOSED AS A HORIZONTAL STANDARD, IDENTIFY AS POSSIBLE, THE CORRESPONDING APPLICABLE GUIDE(S) AND ASSOCIATED ADVISORY COMMITTEE(S) (SEE GUIDE 108).

The market relevance is that the energy yield assessment is one of the key steps in establishing a wind power station that is currently not standardized. The large variation in approaches used by different actors in the wind industry, the low quality of equipment sometimes seen as well as the lack of traceability observed in certain situations leads to a high uncertainty on the expected potential energy for a given site and a high risk to potential developers and investors. If not adequately characterized, this high risk can directly impact the competitiveness of wind energy projects in the market. A common approach to the methodology and reporting requirements will provide a common basis for Energy Yield Assessment (EYA) for developers, OEMs, independent engineers, certification bodies, end users, and financial institutions.

PLEASE SELECT ANY UN SUSTAINABLE DEVELOPMENT GOALS (SDGS) THAT THIS DOCUMENT WILL SUPPORT. FOR MORE INFORMATION ON SDGS, PLEASE VISIT OUR WEBSITE AT HTTPS://WWW.IEC.CH/SDG/

☐ GOAL 1: No Poverty	☐ GOAL 10: Reduced Inequalities
☐ GOAL 2: Zero Hunger	☐ GOAL 11: Sustainable Cities and Communities
☐ GOAL 3: Good Health and Well-being	☐ GOAL 12: Responsible Consumption and Production
☐ GOAL 4: Quality Education	☐ GOAL 13: Climate Action
☐ GOAL 5: Gender Equality	☐ GOAL 14: Life Below Water
☐ GOAL 6: Clean Water and Sanitation	☐ GOAL 15: Life on Land
☒ GOAL 7: Affordable and Clean Energy	☐ GOAL 16: Peace, Justice and Strong Institutions
☒ GOAL 8: Decent Work and Economic Growth	☐ GOAL 17: Partnerships for the Goals
☒ GOAL 9: Industry, Innovation and Infrastructure	

TARGET DATE(S)	FOR FIRST CD: 2025-05-31	FOR PUBLICATION: 2027-06-30	
ESTIMATED NUMBER OF MEETINGS: 6	FREQUENCY OF MEETINGS: 3 per year	DATE OF FIRST MEETING: 2024-09-30	PLACE OF FIRST MEETING: Golden, Colorado, US

RELEVANT DOCUMENTS TO BE CONSIDERED:

IEC 61400-1, Edition 4.0, 2019-02-08, Wind turbines – Part 1: Design requirements

IEC 61400-3, Edition 1.0, 2019-04-05, Wind turbines – Part 1: Design requirements

IEC 61400-12:2022,Edition 1.0, 2022-09-05, Wind turbines – Series on Power performance measurements of electricity producing wind turbines

IEC 61400-15-1 Site Suitability Input Conditions for wind power plants

IEC 61400-50 series for instrumentation and measurements

IEA Wind Task 32: Recommended Practice for Remote Sensing

IEA Wind Task 43: Digital WRA data model

MEASNET: Evaluation of site specific wind conditions version 3

IEC 61400-26: Availability of wind turbines and wind power stations

IEC 60050-415: Vocabulary

RELATIONSHIP OF PROJECT TO ACTIVITIES OF OTHER INTERNATIONAL BODIES:

This activity is related to several existing tasks within IEC TC 88 as well as the broader research community. Specifically standards and research activities that involve targeted aspect of the energy yield process such as measurement technologies, atmospheric or system modelling and digital standards such as:

IEC 61400-1

IEC 61400-3

IEC 61400-12

IEC 61400-15-1

IEC 61400-16

IEC 61400-50

IEA Wind Task 52: Large-scale deployment of wind lidar

IEA Wind Task 43: Wind Energy Digitalization

IEA Wind Task 37: Wind Plant Systems Engineering

IEA Wind Task (#TBD) Wind Jam on wind plant modeling

Consortium for Advancement of Remote Sensing (CFARS)

Power Curve Working Group (PCWG)

American Wake Experiment (AWAKEN)

LIAISONS WITH INTERNATIONAL BODIES: MEASNET, IEA	NEED FOR ISO COORDINATION:
DOCUMENT MATURITY: ☒ A DRAFT IS ATTACHED FOR COMMENT*	☐ AN OUTLINE IS ATTACHED

* Recipients of this document are invited to submit, with their comments, notification of any relevant patent rights of which they are aware and to provide supporting documentation.

CONCERNS KNOWN PATENTED ITEMS (SEE ISO/IEC DIRECTIVES, PART 1)	☐ YES	☒ NO
PATENT DESCRIPTION:		

RECIPIENTS OF THIS DOCUMENT ARE INVITED TO SUBMIT, WITH THEIR COMMENTS, NOTIFICATION OF ANY LOCAL REGULATIONS OR TECHNICAL REASONS THAT MAY EXIST AND SHOULD BE CONSIDERED SHOULD THIS PROPOSAL PROCEED, RECOGNIZING THAT FAILURE TO ADDRESS SUCH REQUIREMENTS COULD RESULT IN THE NEED FOR "IN SOME COUNTRIES" CLAUSES.

CONCERNS LOCAL REGULATIONS OR TECHNICAL DIFFERENCES (SEE AC/22/2007) ☐ YES ☐ NO

DESCRIPTION:

WE NOMINATE A PROJECT LEADER IN ACCORDANCE WITH ISO/IEC DIRECTIVES, PART 1

LAST NAME:	FIRST NAME:	E-MAIL:	COUNTRY:
Sherwin	Robert	VTwindpower@gmail.com	United States of America

COMMENTS AND RECOMMENDATIONS FROM TC/SC OFFICERS:

WORK ALLOCATION:

☐ NEW PROJECT TEAM ☐ NEW WORKING GROUP ☒ EXISTING WORKING GROUP: WG 15

IF APPROVED, THE NEXT STAGE SHOULD BE:

☒ CD ☐ CDV

REMARKS FROM TC/SC OFFICERS:

The proposed work is the extension and completion of IEC 61400-15-2 which has been ongoing for several years. The work was cancelled due to the 5-year deadline.

This New Work Item Proposal (NP) is being circulated to restart the work on background of the decision taken at the TC 88 meeting held 24-25 April 2023 in Aarhus, Denmark:

Decision 6 (Item 9.15-2): "61400-15-2 will be closed as the 5 year deadline has been overrun. NP for restart of 61400-15-2 will be circulated for 8 weeks."

Please note that National Committees will have to appoint experts for this specific work even if they have already have experts in WG 15.

The reason is to meet the approval criteria saying that at least 5 National Committees must nominate experts and approved the NP.

APPROVAL CRITERIA

- Approval of the new work item proposal by a 2/3 majority of the P-members voting;
- At least 4 P-members in the case of a committee with 16 or fewer P-members, or at least 5 P-members in the case of committees with more than 17 P-members, have nominated or confirmed the name of an expert and approved the new work item proposal.

CONTENT

INTERNATIONAL ELECTROTECHNICAL COMMISSION

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WIND ENERGY GENERATION SYSTEMS –

PART 15-2: FRAMEWORK FOR ASSESSMENT AND REPORTING OF THE WIND RESOURCE AND ENERGY YIELD

FOREWORD

1) The International Electrotechnical Commission (IEC) is a worldwide organization for standardization comprising all national electrotechnical committees (IEC National Committees). The object of IEC is to promote international co-operation on all questions concerning standardization in the electrical and electronic fields. To this end and in addition to other activities, IEC publishes International Standards, Technical Specifications, Technical Reports, Publicly Available Specifications (PAS) and Guides (hereafter referred to as “IEC Publication(s)”). Their preparation is entrusted to technical committees; any IEC National Committee interested in the subject dealt with may participate in this preparatory work. International, governmental and non-governmental organizations liaising with the IEC also participate in this preparation. IEC collaborates closely with the International Organization for Standardization (ISO) in accordance with conditions determined by agreement between the two organizations.

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- the required support cannot be obtained for the publication of an International Standard, despite repeated efforts, or
- the subject is still under technical development or where, for any other reason, there is the future but no immediate possibility of an agreement on an International Standard.

Technical specifications are subject to review within three years of publication to decide whether they can be transformed into International Standards.

IEC 61400-15-2, which is a standard, has been prepared by IEC technical committee 88: Wind energy generation systems.

The text of this technical specification is based on the following documents:

Enquiry draft	Report on voting
88/XXX/DTS	88/XX/RVC

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

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

As the title of TC 88 was changed in 2015 from Wind turbines to, Wind energy generation systems a list of all parts of the IEC 61400 series, under the general title Wind turbines and Wind energy generation systems can be found on the IEC website.

Mandatory information categories defined in this Standard are written in capital letters; optional information categories defined are written in bold letters. 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.

A bilingual version of this publication may be issued at a later date.

The National Committees are requested to note that for this publication the stability date is 2025. THIS TEXT IS INCLUDED FOR THE INFORMATION OF THE NATIONAL COMMITTEES AND WILL BE DELETED AT THE PUBLICATION STAGE.

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

This standard defines a framework for assessing and reporting wind resource and energy yield for both onshore and offshore wind power plants. The standard has been prepared with the intention that it will be beneficially applied by:

- **Field Measurement Practitioners:**
  To provide a set of guidelines for the specification and installation of field measurement equipment and management of wind data.
- **Developers:**
  To have a set of guidelines by which to design wind resource assessment campaigns and prepare reproducible and comparable energy yield and site suitability studies.
- **Consultants/Independent Engineers**:
  To have a comprehensive set of standard criteria and project data for the evaluation of projects and the reporting of methodology, uncertainty and losses.
- **Manufacturers:**
  To have a set of standard criteria and input data from which loading and suitability determinations can be calculated.
- **Owner/Operators:**
  To aid in judgement of asset performance and investment quality based on pre-construction analysis.
- **Advisors/Lenders/Banks/Investors/Insurers**:
  To have a standard by which to evaluate an independent energy assessment, and to compare assessments from multiple Consultants/Independent Engineers.
- **Regulatory Authorities:**
  For the assessment of projects proposed for interconnection and the evaluation of cumulative impacts of neighbouring projects.
- **Grid Operators:**
  For the understanding of regional curtailment requirements.
- **Research Organizations:**
  To identify gaps in knowledge, help prioritize research and as an outlet for the results of academic research.

This standard addresses these technical and commercial needs:

- Improve consistency, quality and uniformity of reporting of wind resource and energy yield assessments and site suitability inputs, and
- Enhance ability to compare and evaluate results of wind resource and energy yield assessments and site suitability inputs through common reporting and uncertainty quantification framework.

The following tasks were addressed to meet these goals:

- Develop a standard framework, methods, content, and uncertainty calculations for wind resource and energy yield assessments
- Develop a standard reporting format and digital exchange format for wind resource and energy yield assessments

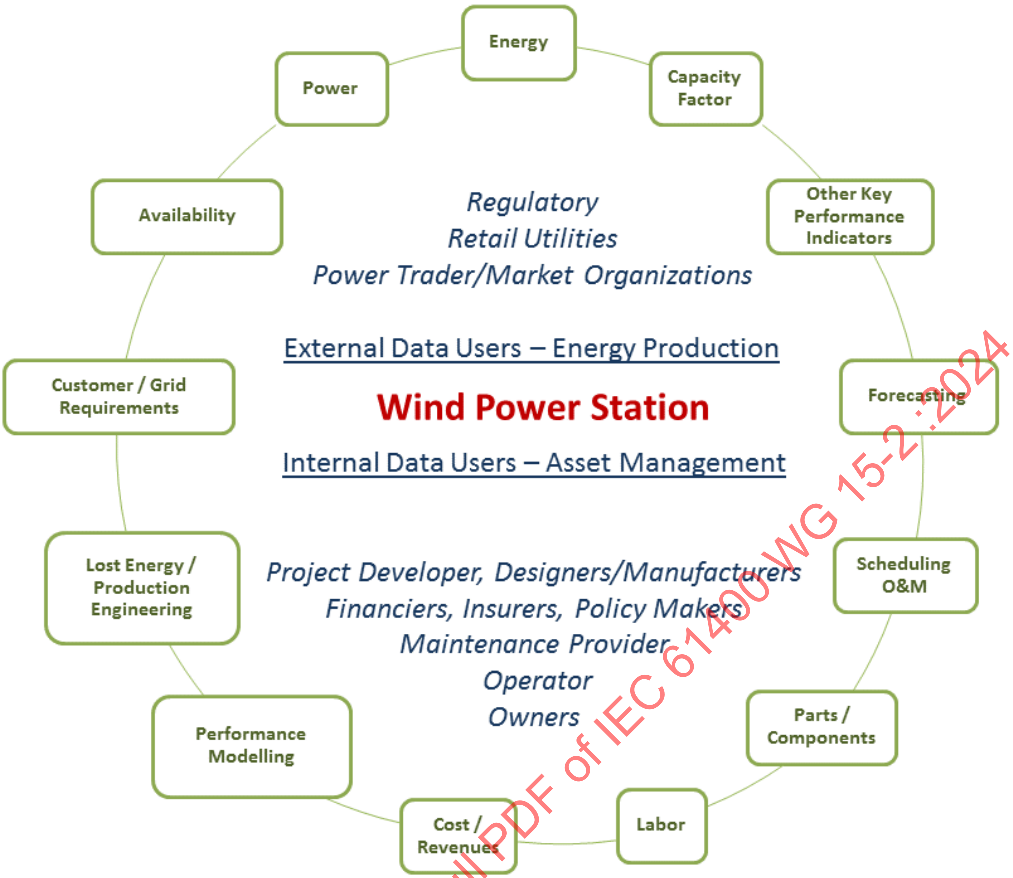


Figure 1 – Data stakeholders for a wind power station

The basic and fundamental goal is to present a standardized framework for reporting and calculating the uncertainties associated with wind resource characterization and energy yield assessments. This will be supported with the development and presentation of methodologies on site assessment and the creation of a set of standard reporting requirements which detail the measurement campaign, analysis processes, and considerations taken by the author. The normative requirements shall not restrict or preclude the employment of scientifically sound methods of measurement, modeling and analysis, but will ensure that the processes and resulting quantification are documented by a standard method.

The methodologies presented provide a framework to evaluate the project data and methods employed to analyse wind resource and site suitability inputs. The reporting procedures will provide transparency to report readers about the considerations taken during analysis and provide confidence that analyses consider all key criteria and procedures identified in this standard.

The uncertainty categorization ensures that results of diverse assessment methods can be commonly described and presented. The standard uncertainty calculation protocols shall further facilitate the inter-comparison of results by providing the minimum requirements for assigning values to the uncertainty categories.

The standardized reporting process provides a discrete list of criteria which must be considered and reported on for all projects, as well as common definitions for key parameters and processes. The uncertainty model defines the contributing components in each of the categories and, where possible, provides techniques for assessing and combining uncertainties. Standardized methods are presented for assessing and reporting site suitability input parameters as defined by the IEC design standards. Best practices, including multiple approaches to common problems and assessment tasks, are presented.

Mandatory information categories defined in the Technical Standard are written in capital letters; optional information categories defined in the Technical Standard are written in bold letters.

WIND ENERGY GENERATION SYSTEMS –

PART 15-2: FRAMEWORK FOR ASSESSMENT AND REPORTING OF THE WIND RESOURCE AND ENERGY YIELD

1 Scope

This part of IEC 61400, which is a standard, provides a framework for assessment and reporting of the wind resource and energy yield both onshore and offshore wind power plants. This includes:

1) Definition, measurement, and prediction of the long-term meteorological and wind flow characteristics at the site
2) Integration of the long-term meteorological and wind flow characteristics with wind turbine and balance of plant characteristics to predict net energy yield
3) Characterizing environmental extremes and other relevant plant design drivers
4) Assessing the uncertainty associated with each of these steps
5) Addressing documentation and reporting requirements to help ensure the traceability of the assessment processes and efficient exchange of results

The framework has been defined such that applicable national norms are considered and industry best practices are utilized.

The meteorological and wind flow characteristics addressed in this document relate to wind turbine operating conditions, where parameters such as wind speed, wind direction, air density or air temperature are included to the extent that they affect the operation and structural integrity of wind turbine generating systems and energy production analysis.

According to IEC 61400-1 and 61400-3 the site-specific conditions can be broken down into wind conditions, other environmental conditions, soil conditions, ocean/lake conditions and electrical conditions. All of these site conditions other than site specific wind conditions and related documents are out of scope for this standard.

This standard is framed to complement and support the scope of related IEC 61400 series standards by defining environmental input conditions. It is not intended to supersede the design and suitability requirements presented in those standards. Specific analytical and modeling procedures as described in IEC 61400-1, 61400-2, and 61400-3 are excluded from this scope.

This document also includes informative annexes with:

- Annex A:
- Annex B:
- Annex C:
- Annex D: examples of how to determine the loss and uncertainty category for the wind power station,

2 Normative references

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.

IEC 60050 (all parts), *International Electrotechnical Vocabulary* (available at <http://www.electropedia.org/)

IEC 61400-1, *Wind turbines – Part 1: Design requirements*

IEC 61400-12:2016, *Wind turbines – Part 1: Power Performance Testing*

IEC TS 61400-26-1:2011, *Wind turbines – Part 26-1: Time-based availability for wind turbine generating systems*

IEC TS 61400-26-2:2014, *Wind turbines – Part 26-2: Production-based availability for wind turbines*

3 Terms, definitions and abbreviations

For the purposes of this document, the following terms, definitions and abbreviations apply, as well as the relevant terms and definitions contained in IEC TS 61400-26-1, IEC TS 61400-26-2 and IEC 60050-415.

3.0
actual service
the actual level of a Service provided by the WPS as measured at the network connection point

3.1
application programming interface (API)
a software interface that facilitates communication between computer systems

Note 1 to entry: Wind EYA DEF data may be exchanged over APIs.

3.2
balance of plant (BoP)
infrastructure components of the WPS with the exception of the WTGS(s) and its internal components and subsystems

Note 1 to entry: The infrastructure normally consists of site electrical facilities, monitoring and control (often called SCADA) as well as civil plant (such as foundations and roads) which support the operation and maintenance of the WTGS(s).

3.3
capacity
the lesser of the installed capacity and export capacity for a WPS, which represents the maximum power the WPS can produce and export, and is used as the reference power when calculating the capacity factor

3.4
capacity factor
an energy yield estimate normalised by the energy yield that would be produced if the WPS output was always at full capacity, expressed as a percentage

Note 1 to entry: Gross Capacity Factor (GCF) is the capacity factor where the numerator is based on the energy yield from the turbines based on their wind speed frequency distribution and power curve, prior to the application of losses from gross energy capacity factor. Net Capacity Factor (NCF) is the capacity factor where the numerator is based on the energy yield after applying losses from gross capacity factor.

3.5
complex terrain (from IEC 61400-1)
surrounding terrain that features significant variations in topography and/or terrain obstacles that may cause flow distortion

3.6
constrained potential service
the calculated level of a Service provided by the WPS as measured at the network connection point based on design criteria, technical and operating specifications, and site conditions

Note 1 to entry: Operating specifications shall include externally caused set-points such as Grid or contractually imposed constraints.

3.7
cross prediction
Predict an attribute at one measurement location based on input data to a flow model that is restricted to input conditions from a single measurement location based on the data from a single different measurement location.

3.8
Ct
Thrust coefficient

3.9
energy yield assessment digital exchange format (EYA DEF) for wind
a schema (data model) for wind EYA reporting data defined as part of this standard to facilitate automated data exchange by software systems

3.10
energy weighting (w_m or w_n)the energy weighting is the fraction of plant energy represented by each mast, expressed as a percentage

3.11
ERA
ECMWF atmospheric reanalyses of the global climate; the current generation is the fifth-generation which is referred to as ERA5.

3.12
export capacity
the maximum permanently transmittable power from the **WPS** at the grid connection

3.13
flow field
Wind flow calculations in a structured grid of calculation points which can be visualized within a given domain or defined polygon encompassing the area of interest

3.14
flow inclination
Terrain induced flow direction away from horizontal. (“+”=upward, “-“=downwind)

3.15
Grid
electrical network to which the WPS is electrically connected

Note 1 to entry: The WPS delivers its services into the Grid. The interface between the Grid and the WPS internal electrical system is the network connection point often referred to as the Point of Common Coupling (PCC).

3.16
installed capacity
the maximum power production of the **WPS** under typical conditions

3.17
intended function
the ability of an apparatus, machine or system to consistently perform its required function within its design specification

3.18
inter-mast correlation coefficient (c_{mn})
the inter-mast correlation coefficient, expressed as a unitless value between 0 and 1, is a measure of the strength of a linear relationship between categories and subcategories of uncertainty across masts

3.19
JavaScript Object Notation
JSON
an open and widely used data-interchange and file format

3.20
JSON Schema
a declarative language for defining JSON document structure, adding annotations to that structure and facilitating data validation

Note 1 to entry: The **EYA DEF** takes the form of a JSON Schema.

3.21
lost service
a service not supplied

Note 1 to entry: See **Error! Reference source not found.**.

3.22
mean wind speed (from IEC 61400-1)
statistical mean of the instantaneous value of the wind speed averaged over a given time period which can vary from a few seconds to many years

3.23
model appropriateness
Physical scientific and demonstrated ability of model to capture influencing factors

3.24
model inputs
Fidelity & appropriateness given sensitivity of model to - terrain data, roughness, forestry info, atmospheric conditions

3.25
model stress
Magnitude of variation and complexity of influencing factors (e.g. Forestry, Stability, steep slopes, distance, elevation, veer) acting on the model when determining wind conditions for the turbine locations

3.26
observation height

3.27
OEPR
Operational Energy Production Report; a report that describes the result of energy yield analysis based on operational data.

3.28
OEPR verification process
method that the on-site wind measurements by production data from nearby existing wind turbines replaces in a wind potential and energy yield assessment procedure. The original driving wind data for

a flow model, e.g. Mesoscale data or ERA5/Merra-2 data, are verified, or – if necessary – adjusted by using this production data of the nearby wind turbines.

3.29
OP
abbreviation for “Operational“

3.30
orographic effects
Orography=terrain, aka terrain effects. Detached flow/speed-ups/speed-downs at mountains, hills or valleys.

3.31
physical potential service
the calculated level of a Service provided by the WPS as measured at the network connection point based on design criteria, technical specifications and site conditions

Note 1 to entry: The potential service is the physically possible level of service.

3.32
potential service
calculated value of physical potential service or constrained potential service as is appropriate

3.33
prediction height

3.34
reference wind speed V_{ref} (from IEC 61400-1)
basic parameter for wind speed used for defining wind turbine classes.

Note 1 to entry: A turbine designed for a wind turbine class with a reference wind speed V_{ref}, is designed to withstand climates for which the extreme 10 min average wind speed with a recurrence period of 50 years at turbine hub height is lower than or equal to V_{ref}.

3.35
roughness length z_0 (from IEC 61400-1)
extrapolated height at which the mean wind speed becomes zero if the vertical wind profile is assumed to have a logarithmic variation with height

3.36
sensitivity factor

$$s_{UE} \equiv \frac{\partial E}{\partial U} \simeq \frac{\Delta E}{\Delta U}$$

the sensitivity factor, expressed as ratio, is the change in plant energy output (ΔE) per unit change in wind speed (ΔU)

3.37
site ruggedness index, RIX
complex terrain indicator: percentage of local terrain possessing a slope which exceeds a critical value of 0.3 [Mortensen *et al.*, 1996]; referred to as “RIX”

3.38
service
provision delivered by the WPS

Note 1 to entry: Services may include, but are not limited to, supply of active energy, reactive energy and support of electrical stability of the Grid. Aviation warning is another example of a Service.

3.39
spatial extrapolation
Horizontal extrapolation of wind conditions from measurement location(s) to wind turbine location(s)

3.40
stability (atmospheric)
Atmospheric stability refers to a particular state of the atmosphere and there are two formally defined terms from the field of atmospheric science, dynamic stability and static stability. Dynamic stability is a measure of the ability of a fluid to resist or recover from finite perturbations of a steady state and is commonly described by the Richardson Number. A negative value of dynamic stability is equivalent to dynamic instability. Static stability, also called hydrostatic stability or vertical stability, is the ability of a fluid at rest to become turbulent or laminar due to the effects of buoyancy. Static stability is commonly described by the change in potential temperature with height, or approximated, with appropriate care, by the change in air temperature with height.

3.41
supervisory control and data acquisition (SCADA)
system operating with signals over communication channels so as to provide control of equipment and for gathering and analysing real-time data

3.42
total uncertainty (σ_{total})
the total combined uncertainty, expressed as a percent of energy, is the standard deviation (standard uncertainty) of the distribution of combined energy uncertainties from all categories and subcategories listed in Table 8-1 and Table 8-2

3.43
transmission system operator (TSO)
operator that transmits electrical power from generation plants over the Grid to regional or local electricity distribution operator

3.44
uncertainty components (σ_i, σ_j)
the uncertainty estimate, expressed as a percent of wind speed or energy, from each of the categories and subcategories listed in Table 8-1 and Table 8-2

3.45
veer

Veering winds are those which shift in a clockwise direction with time at a given location (e.g., from southerly to westerly), or which change direction in a clockwise sense with height (e.g., southeasterly at the surface turning to southwesterly aloft). The latter example is a form of directional shear which is important for tornado formation. Compare with backing winds. Which are winds which shift in a counterclockwise direction with time at a given location (e.g. from southerly to southeasterly), or change direction in a counterclockwise sense with height (e.g. westerly at the surface but becoming more southerly aloft). In the practice of wind energy analysis, the term veer is often used to refer to the quantity of wind direction change with height, regardless of whether the change is clockwise or counterclockwise.

3.46
vertical extrapolation
extrapolation of mean wind speed or Weibull-*A* parameter from one height above ground level (observation height) to another (prediction height)

3.47
Weibull distribution P_W (from IEC 61400-1)

3.48

probability distribution function, see wind speed distribution

3.49
wind power station (WPS)
station consisting of the WTG(s) and the infrastructure (often called BoP) which support transfer of energy between the WTG(s) and the Grid

3.50
wind profile – wind shear law (from IEC 61400-1)
mathematical expression for assumed wind speed variation with height above ground

NOTE Commonly used profiles are the logarithmic profile

$$V(z) = V(z_r).\frac{\ln(z/z_0)}{\ln(z_r/z_0)} \qquad (I.1)$$

and the power law profile

$$V(z) = V(z_r)\cdot\left[z/z_r\right]^{\alpha} \qquad (I.2)$$

where

V(z) is the horizontal wind speed at height z;

z is the height above ground;

z_r is a reference height above ground used for fitting the profile;

z0 is the roughness length; and

a is the wind shear (power law) exponent.

3.51
wind shear (from IEC 61400-1)
variation of wind speed across a plane perpendicular to the wind direction

3.52

wind shear exponent α (from IEC 61400-1)
also commonly known as power law exponent, see wind profile – wind shear law

3.53
wind speed *V* (from IEC 61400-1)
at a specified point in space it is the speed of motion of a minute amount of air surrounding the specified point

3.54
wind speed distribution (from IEC 61400-1)
probability distribution function, used to describe the distribution of wind speeds over an extended period of time

NOTE Often used distribution functions are the Rayleigh, PR(Vo), and the Weibull, PW(Vo), functions

$$P_R(V_0) = 1 - \exp\left[-\pi\left(V_0/2V_{ave}\right)^2\right]$$
$$P_W(V_0) = 1 - \exp\left[-\left(V_0/C\right)^k\right] \qquad (I.3)$$

$$with\ V_{ave} = \left\{\begin{matrix} C\,\Gamma(1+\frac{1}{k}) \\ C\sqrt{\pi}/2,\ if\ k=2 \end{matrix}\right\} \qquad (I.4)$$

where

P(V0) is the cumulative probability function, i.e. the probability that V<Vo;

V0 is the wind speed (limit);

Vave is the average value of V;

C (or A) is the scale parameter of the Weibull function;

k is the shape parameter of the Weibull function;

G is the Euler gamma function.

Both C and k can be evaluated from real data. The Rayleigh function is identical to the Weibull function if k = 2 is chosen and C and Vave satisfy the condition stated in (equation I.4) for k = 2.

The distribution functions express the cumulative probability that the wind speed is lower than V0. Thus (P(V1) – P(V2)), if evaluated between the specified limits V1 and V2, will indicate the fraction of time that the wind speed is within these limits. Differentiating the distribution functions yield the corresponding probability density functions

3.55
WPS maintenance provider
provider typically providing the maintenance of the WPS or parts therein. WPS maintenance can be performed by multiple providers

3.56
WPS operator
operator typically responsible for providing the services of the WPS to off-takers

3.57
WTG
wind turbine generator

4 Symbols and Units

4.0 Symbols

A (or C)	scale-parameter of the Weibull distribution	[m/s]
$D_{TV,360}$	standard deviation of terrain variation Δz of the 360-degree circle area	[m]
f	frequency	[s^{-1}]
k	shape parameter of the Weibull distribution function	[-]
$P_R(V_0)$	Rayleigh probability distribution, i.e. the probability that $V<V_0$	[-]
$P_W(V_0)$	Weibull probability distribution	[-]
$V(z)$	wind speed at height z	[m/s]
V_{ave}	annual average wind speed at hub height	[m/s]
V_{eN}	expected extreme wind speed (averaged over three seconds), with a recurrence time interval of N years. V_{e1} and V_{e50} for 1 year and 50 years, respectively	[m/s]
V_{pred}	wind speed at prediction (e.g. hub) height	[m/s]
V_{50}	Extreme wind speed (avg. over 10 minutes) with recurrence interval of 50 years	[m/s]
V_{ref}	reference wind speed	[m/s]
$V(z,t)$	longitudinal wind velocity component to describe transient variation for extreme gust and shear conditions	[m/s]
x, y, z	co-ordinate system used for the wind field description; along wind (longitudinal), across wind (lateral) and height respectively	[m]
z_{hub}	hub height of the wind turbine	[m]
z_r	reference height above ground	[m]
z_0	roughness length for the logarithmic wind profile	[m]
α	wind shear power law exponent	[-]

$\tilde{\sigma}_{U,\mathrm{ve}}$ dimensionless uncertainty in vertical extrapolation of mean wind speed or Weibull-scale *parameter* [-]

$\tilde{\sigma}_{U_{\mathrm{obs}}}$ dimensionless uncertainty of wind speed measurement [-]

$\tilde{\sigma}_{\mathrm{rep}}$, $\tilde{\sigma}_{\mathrm{prop}}$, $\tilde{\sigma}_{\alpha\mathrm{fit}}$ dimensionless uncertainty subcomponents [-]

RIX site ruggedness index [%]

4.1 Units

min

minute

km

kilometre

5 Introduction to Wind Resource and Energy Yield Assessment (EYA)

Wind Resource and Energy Yield Assessment (EYA) is the process by which energy to be produced by a WPS is estimated given relevant input data and assumptions. The outputs of the EYA process are typically used to inform strategic, project development, pricing/bidding, and associated or final financial investment decisions on a project or portfolio level. Input data minimally include WTG locations, topographic and physiographic information, meteorological measurements or operational data from reference wind turbine, and wind turbine power curves. Depending on WPS complexity and commercial requirements, additional data inputs may be deemed necessary. EYA output is typically presented as a distribution of potential energy outcomes on an annual or multi-year basis. Key attributes that are reported include a central estimate, at the 50% probability of exceedance level (“P50”), as well as estimates to support commercial risk assessment. Typical estimates include the 90% probability of exceedance level (“P90”) and 95% probability of exceedance level (“P95”). Probability of exceedance levels are determined based on wind resource measurement uncertainty, wind resource variability, modeling uncertainties and uncertainties in plant performance loss estimates. This standard makes normative two key components of the energy yield process. The first is the uncertainty quantification that creates the PXX distributions. The second is the reporting requirements for communicating the EYA methods and metrics between analysts and stakeholders. In additional chapters below, a process for gathering and analyzing meteorology measurements and in particular long-term mean annual wind speeds and their frequency distribution, estimating gross energy generation for each WTG and project aggregate, losses from gross energy, net energy and uncertainty of the results is described.

5.0 Process Overview

5.0.0 Gross Energy Calculation

5.0.1 Losses and Net Energy Calculation

5.0.2 Uncertainty Assessment

5.0.3 Reporting

6 Input Data

6.0 Site Description

6.1 Turbine Technology Description

6.2 Wind Turbine Layout

6.3 Proximal Wind Farms

6.4 Wind Resource Information

Meteorological data and operational data

6.5 Loss and Uncertainty Assumptions

6.6 Other commercial process inputs

7 Wind Energy Yield Assessment Reporting

The main objective of this standard with regard to reporting is to establish commonality among wind energy yield assessment reports from different providers, so that the audience of such reports can efficiently review and compare multiple reports and determine the differences in key results. However, a competing objective is to maintain enough flexibility within the reporting structure to allow analysts to organize the report in such a way that highlights their own strengths, to relay the narrative of the wind EYA process in the way that makes the most sense to their audience, and to foster innovation to improve the underlying methods.

To this end, the standard will provide three normative requirements for wind energy yield assessment reporting:

1. Summary tables
2. Reporting elements
3. A digital exchange format for wind energy yield assessment (the EYA DEF)

The locations of the summary tables and reporting elements within the report and the precise sectional order and organization of the report are not normative. However, an informative table of contents for a compliant energy yield assessment report is provided in Annex A.

The digital exchange format defines a complementary format for reporting to the main written report, aimed at facilitating automated solutions for data exchange, and is published in the form of a JSON Schema. Whereas the written report provides an effective narrative for a human reader, the digital exchange format provides the clear definitions of namespace, structure and format required for computer systems to exchange energy yield assessment data. The digital exchange format is only concerned with standardising data structure and does not introduce any new normative requirements in terms of content beyond those provided by the summary tables and reporting elements. The wind EYA DEF can bridge the gap of facilitating efficient data exchange and comparison whilst leaving a degree of flexibility in the presentation of the content in the written report.

7.0 IEC Summary Tables

The following five summary tables for energy yield, losses, and uncertainties shall be included in the report, to be identified as IEC Tables A through to E. An additional table summarising data sources and methods may be included, to be identified as IEC Table F. The tables will be located in the Executive Summary of the report, with the recommended location being at the end of the Executive Summary. If results for multiple scenarios are being provided in the report, the tables should be repeated for each scenario. For more than one scenario, it is recommended that results for one scenario be presented within the Executive Summary, and tables for the remaining scenarios be placed in an appendix.

The digital exchange format encompasses all energy yield assessment data required to generate the IEC Summary Tables, though organised in a deeply nested hierarchical structure rather than table views. It is anticipated that tools will become available to translate a digital exchange format document into the IEC Summary Tables.

7.0.0 Scenario Comparison

The energy yield assessment may be one of several prepared for the same project, with each report considering one scenario with a different turbine layout, turbine technology, updated measurement campaign, etc. Similarly, several scenarios may be included within the same report. The following table helps the reader understand how the scenario for the present report differs from those in other relevant assessments and/or how the multiple scenarios within the report differ. The rows in italics shall be included. The non-italic rows shall be included only if they differ between the scenarios. At least all the different scenarios presented within the report shall be included. Scenarios from other reports can be included as relevant, at the discretion of the author.

IEC Table A: Scenario Comparison

Scenario number	1	2 (current report)	3
Installed capacity [MW]			
Export capacity [MW]			
Number of turbines			
Turbine model(s)			
Turbine rated power [MW]			
Turbine rotor diameter [m]			
Turbine hub height [m]			
Layout identifier			
Existing external projects included			
Future external projects included			

Option for other differentiator(s)			

Explanatory and Guidance Notes:

- Installed capacity and export capacity: the maximum production of the WPS under typical conditions and the maximum permanently transmittable power from the WPS at the grid connection, respectively (also see the terms, definitions and abbreviations section for definitions of the different capacity terms). If the WPS under assessment does not have an export capacity limitation, or it is unknown and assumed to be the full installed capacity, the row for export capacity can be omitted. The capacity of the WPS is defined as the lesser of the installed capacity and export capacity, and it is recommended to highlight this value for each scenario, for example with a table note.
- Option for other differentiator(s): other categories that the author believes are relevant and advantageous, such as differences in curtailments between different scenarios.

7.0.1 Annual Energy Production

These overall project AEP numbers are expressed both as energy (in GWh) and as capacity factor (in percent), except the total annual plant performance efficiency is expressed as a percentage efficiency (loss factor) relative to gross energy.

The reference power to which the capacity factor is defined by shall be the capacity of the WPS defined as the lesser of the installed capacity and the export capacity, as outlined for each scenario in IEC Table A.

IEC Table B: Annual Energy Production

Scenario number (if applicable)	1	2	3
Gross Annual Energy Production	1039.5 / 49.3%	1039.5 / 49.3%	1039.5 / 49.3%
Annual Plant Performance Efficiency	89.5%	89.5%	89.5%
Fixed / Variable	Variable	Variable	Variable
Net Annual Energy Production	930.4 / 44.1%	930.4 / 44.1%	930.4 / 44.1%
Reference Period	(20 years)	(20 years)	(20 years)
Option for other differentiator(s)			

1: Annual Energy Production Time Varying Plant Performance Efficiency

Scenario number (if applicable)	1	2	3

Year			
1	88.5%		
2	89.0%		
3 (and subsequent years)	89.5%		
10 (and subsequent years)	89.0%		
20 (and subsequent years)	88.5%		
30 (and subsequent years)	88.0%		

7.0.2 Uncertainty and Probability of Exceedance Values

If in markets relevant to the project under consideration different probability levels or time periods are considered standard, those can be added as additional rows and/or columns in the table shown below. However, none of the rows or columns shown should be excluded.

IEC Table C: Uncertainty in Annual Energy Production

Scenario number		Energy / Capacity factor			
		1-year	10-year	Lifetime (i.e. 20)-year	XX year
1	Uncertainty (Percent of Net)	8.0%	7.7%	7.6%	7.6%
	Fixed / Variable	Variable	Variable	Variable	Variable
	P75 Net Energy Production	880.0 GWh / 41.7%	881.5 GWh / 41.8%	881.6 GWh / 41.8%	881.6 GWh / 41.8%
	P90 Net Energy Production	834.5 GWh / 39.6%	837.4 GWh / 39.7%	837.6 GWh / 39.7%	837.6 GWh / 39.7%
	PXX Net Energy Production	834.5 GWh / 39.6%	837.4 GWh / 39.7%	837.6 GWh / 39.7%	837.6 GWh / 39.7%
2	Uncertainty (Percent of Net)	8.0%	7.7%	7.6%	7.6%
	Fixed / Variable	Variable	Variable	Variable	Variable
	P75 Net Energy Production	880.0 GWh / 41.7%	881.5 GWh / 41.8%	881.6 GWh / 41.8%	881.6 GWh / 41.8%
	P90 Net Energy	834.5 GWh /	837.4 GWh /	837.6 GWh /	837.6 GWh /

	Production	39.6%	39.7%	39.7%	39.7%
	PXX Net Energy Production	834.5 GWh / 39.6%	837.4 GWh / 39.7%	837.6 GWh / 39.7%	837.6 GWh / 39.7%
3	Uncertainty (Percent of Net)	8.0%	7.7%	7.6%	7.6%
	Fixed / Variable	Variable	Variable	Variable	Variable
	P75 Net Energy Production	880.0 GWh / 41.7%	881.5 GWh / 41.8%	881.6 GWh / 41.8%	881.6 GWh / 41.8%
	P90 Net Energy Production	834.5 GWh / 39.6%	837.4 GWh / 39.7%	837.6 GWh / 39.7%	837.6 GWh / 39.7%
	PXX Net Energy Production	834.5 GWh / 39.6%	837.4 GWh / 39.7%	837.6 GWh / 39.7%	837.6 GWh / 39.7%

1: Annual Energy Production Time Varying Uncertainty

Scenario number (if applicable)	1				2				3			
Duration	1-year	10-year	Lifetime (i.e. 20)-year	XX year	1-year	10-year	Lifetime (i.e. 20)-year	XX year	1-year	10-year	Lifetime (i.e. 20)-year	XX year
Year												
1												
2												
3												
10												
20												
30												

7.0.3 Categorical Wind Speed-Based Uncertainties

The categorical wind speed-based uncertainties are expressed in this table as a percent of annual mean wind speed. All values reported in the table shall be calculated according to the normative methods described elsewhere in this standard, with the following exception: the author of the report may use an alternative uncertainty calculation for a subcategory, provided that the method of calculation and assumptions made are described in the report, and that those methods and assumptions are supported with citable studies.

The final row of the table is not a percentage uncertainty. Rather, it is the wind energy sensitivity factor used to convert wind speed-based uncertainties to energy-based uncertainties.

IEC Table D: Details of Wind Speed-based Uncertainties

	Uncertainty (% of Wind Speed)		
Scenario number (if applicable)	1	2	3
Measurement Uncertainty			
Wind Speed Measurement			
Wind Direction Measurement / Rose			
Other Atmospheric Parameters			
Data Integrity and Documentation			
Historical Wind Resource			
Long-term Period (IAV)			
Reference Data			
Long-term Adjustment (MCP/method)			
(Wind Speed) Distribution Uncertainty			
On-site Data Synthesis (gap filling)			
Horizontal Extrapolation			
Model Inputs			
Model Sensitivity/Stress			
Model Appropriateness			
Vertical Extrapolation			
VE model Uncertainty			

Excess Propagated Measurement Uncertainty			
Project Evaluation Period Variability			
Wind speed variability (IAV)			
Climate Change			
Plant Performance (avail., environ.)			
Wind Energy Sensitivity Factor			

7.0.4 Categorical Plant Performance Losses and Uncertainties

Loss calculation methods are not normative in this standard, but their categorization and table for reporting them is normative. They are expressed in the table as a percentage of gross energy.

The categorical loss uncertainties are expressed in this table as a percent of gross energy. All values reported in the table shall be calculated according to the normative methods described elsewhere in this standard, with the following exception: the author of the report may use an alternative uncertainty calculation for a subcategory provided that the method of calculation and assumptions made are described in the report, and that those methods and assumptions are supported with citable studies.

IEC Table E: Details of Plant Performance Losses and Uncertainties

Scenario number (if applicable)	1		2		3	
Loss Category / Subcategory	Efficiency	Uncertainty	Efficiency	Uncertainty	Efficiency	Uncertainty
Wakes and Other Turbine Interaction Effects						
Internal Wakes, Blockage and Other Turbine Interaction Effects						
External Wakes, Blockage and Other Turbine Interaction Effects						
Future Wakes, Blockage and Other Turbine Interaction Effects						
Availability						
Turbine						
BOP						
Grid						
Electrical						

Electrical Efficiency						
Facility Parasitic Consumption						
Turbine Performance						
Sub-optimal Performance						
Generic Power Curve Adjustment						
Site-specific Power Curve Adjustment						
High Wind Hysteresis						
Environmental						
Icing						
Degradation						
Environmental Loss (External conditions)						
Exposure Changes						
Curtailment / Operational Strategies						
Load Curtailment						
Grid Curtailment						
Environmental / Permit Curtailment						
Operational Strategies						

Explanatory and Guidance Notes:

An example is presented below:

Scenario number (if applicable)	1		2		3	
Loss Category / Subcategory	Efficiency	Uncertainty	Efficiency	Uncertainty	Efficiency	Uncertainty
Wakes and Other Turbine Interaction Effects	**0.9426**	**1.15%**	**0.9426**	**1.15%**	**0.9426**	**1.15%**
Internal Wakes, Blockage and Other Turbine Interaction Effects	0.9500		0.9500		0.9500	
External Wakes, Blockage and Other Turbine Interaction Effects	0.9800		0.9800		0.9800	
Future Wakes, Blockage and Other Turbine Interaction Effects	0.9800		0.9800		0.9800	
Availability	**0.9639**	**1.80%**	**0.9639**	1.80%	**0.9639**	1.80%
Turbine	0.9700	1.50%	0.9700	1.50%	0.9700	1.50%
BOP	0.9800	1.00%	0.9800	1.00%	0.9800	1.00%
Grid	0.9990	0.05%	0.9990	0.05%	0.9990	0.05%
Electrical	**0.9639**	**0.72%**	**0.9639**	0.72%	**0.9639**	0.72%
Electrical Efficiency	0.9700	0.60%	0.9700	0.60%	0.9700	0.60%
Facility Parasitic Consumption	0.9800	0.40%	0.9800	0.40%	0.9800	0.40%
Turbine Performance	**0.9868**	**0.66%**	**0.9868**	**0.66%**	**0.9868**	**0.66%**

Sub-optimal Performance	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Generic Power Curve Adjustment	0.9900	0.50%	0.9900	0.50%	0.9900	0.50%
Site-specific Power Curve Adjustment	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
High Wind Hysteresis	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Environmental	**0.9900**	**0.50%**	**0.9900**	**0.50%**	**0.9900**	**0.50%**
Icing	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Degradation	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Environmental Loss (External conditions)	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Exposure Changes	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Curtailment / Operational Strategies	**0.9900**	**0.50%**	**0.9900**	**0.50%**	**0.9900**	**0.50%**
Load Curtailment	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Grid Curtailment	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Environmental / Permit Curtailment	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Operational Strategies	0.9950	0.25%	0.9950	0.25%	0.9950	0.25%
Total	**0.8470**	**2.46%**	**0.8470**	**2.46%**	**0.8470**	**2.46%**

7.0.5 Data Sources and Methods

In addition, the following table summarising data sources and methods is recommended for inclusion in the report. Unlike the other tables, which are quantitative, this table is descriptive, hence additional guidance to competing the table is offered. For an assessment based on operational data of reference wind farms or turbines, use the Reference Wind Farm related lines of below Table F.

IEC Table F: Data Sources and Methods Summary

Category			***Source / Method***	***Details and Comments***
Wind Data	***Primary (A)***	***Source***	LiDAR	
		Number of Stations	2	
		Top Sensor Height(s)	150 m	
		Period	Oct ’18 – Sep ‘20	
		Duration	2 years	
	Supplementary (A) (Optional)	***Source(s)***	Met Mast, LiDAR, SoDAR	
		Number of Stations	4	

		Height(s)	30m, 60m, 93m	
		Period	2012 - 2016	
		Duration	5 years	
	Long-term (A) (Optional)	***Source(s)***	ERA5 Reanalysis	
		Number of Stations or Grid Nodes	3	
		Height(s)	100 m	
		Period	2001 - 2020	
		Duration	20 years	
Reference wind farm	***Name of Primary WF***	***Weighting***	80%	
		Manufacturer	Enercon	
		Turbine Model	E-101	
		Rated Power [MW]	3.05	
		Number of Turbines	10	
		Hub Height(s)	149 m	
		Available Data Period	Oct '18 – Sep '20	
		Duration	2 years	
		Distance to Planned WF [km]	3.2	
	Name of Supplementary WF	***Weighting***	20%	
		Manufacturer	GE	
		Turbine Model	1.5s	
		Rotor Diameter [m]	70.5	
		Number of Turbines	3	
		Hub Height(s)	100 m	
		Data Type	Scada, 10min-no-Scada, hourly, weekly monthly	
		Available Data Period	Oct '18 – Sep '20	
		Duration	2 years	

		Distance to Planned WF [km]	2.8	
	Long-term (A) (Optional)	***Source(s)***	ERA5 Reanalysis	
		Number of Stations or Grid Nodes	3	
		Height(s)	100 m	
		Period	2001 - 2020	
		Duration	20 years	
Terrain Model	***Orography***		SRTM 30 m 1 Arc-sec	
	Roughness		CORINE 100 m	
Wind flow Model	***Vertical***		12 sector	
	Horizontal		Mesoscale Model A	
WTG (for each Scenario)	***Power Curve***		WTG A 0001.0001 AA	
	Thrust Curve		WTG A 0001.0001 AA	
Losses	***Wakes and other Turbine Interaction Effects***		Insert	
	WTG & BoP Availability		Universal / Preliminary / Design Study	
	Electrical Efficiency		Assumption / Preliminary / Design Study	
	Environmental		Assumption / Preliminary / Design Study	
	Curtailment / Operational Strategies		Assumption / Preliminary / Design Study	
	Other			

7.0.6 Categorical Plant Performance Losses and Uncertainties as Applied to Reference Wind Farms

To gain the free wind speed, in case of assessing the energy yield of the planned wind farm on the basis of the operational production of reference wind farms or turbines, categorical losses that are included in the operational data must be considered. In Table XX these losses are considered and expressed the same way as they are for the planned future wind farm.

IEC Table ??E: Details of Reference Plant Performance Losses and Uncertainties

Scenario number (if applicable)	1		2		3	
Loss Category / Subcategory	Efficiency	Uncertainty	Efficiency	Uncertainty	Efficiency	Uncertainty
Wakes and Other Turbine Interaction Effects						
Internal Wakes, Blockage and Other Turbine Interaction Effects						
External Wakes, Blockage and Other Turbine Interaction Effects						
Future Wakes, Blockage and Other Turbine Interaction Effects						
Availability						
Turbine						
BOP						
Grid						
Electrical						
Electrical Efficiency						
Facility Parasitic Consumption						
Turbine Performance						
Sub-optimal Performance						
Generic Power Curve Adjustment						
Site-specific Power Curve Adjustment						
High Wind Hysteresis						
Environmental						
Icing						
Degradation						
Environmental Loss (External conditions)						

Exposure Changes						
Curtailment / Operational Strategies						
Load Curtailment						
Grid Curtailment						
Environmental / Permit Curtailment						
Operational Strategies						

Explanatory and Guidance Notes:

- Wind data
  - Primary refers to the main source(s) of wind data used for the wind resource assessment. Each type of data source should be listed separately. The most common types of data sources will be “Met Masts”, “LiDAR”, “Floating LiDAR”, “Scanning LiDAR”, or “SoDAR”. If more than one type was used as a primary data source, append the word “Primary” with an uppercase letter (e.g. “A”, B”, “C” etc.).
  - Supplementary refers to all other source(s) of wind data used as additional input and partial elements to the wind resource assessment. As with “Primary”, each type of data source should be listed separately. If more than one type was used as a supplementary source, append the word “Supplementary” with an uppercase letter (e.g. “A”, B”, “C” etc.).
  - Long-term refers to the long period wind data time series used to determine the long term adjustment. Each type of data source should be listed separately. The most common types of data sources will be “reanalysis”, “mesoscale”, “meteorological office measurement masts”. If more than one type was used as a primary data source, append the word “Long-term” with an uppercase letter (e.g. “A”, B”, “C” etc.).
- Terrain model
  - Orography model; Report the type of the digital elevation model used for the orography description and its resolution, e.g. SRTM, ASTER, NED etc. / 30 m 1 arc-second.
  - Roughness model; Report the type of the landcover model used for the roughness description and its resolution, e.g. CORINE, ESA, Copernicus etc. / 10 m, 3 arc-second.
- Wind flow model
  - Vertical: Indicate the number of sectors used for the vertical extrapolation to hub height with the application of the wind shear exponents, or other methodology.
  - Horizontal: Report the model used for the horizontal extrapolation of the mean wind speed from the primary wind data source to the WTG sites.
- WTG Power Curve: Report the document ID and revision of the power curve(s) used for each relevant scenario(s).
- WTG Thrust Curve: Report the document ID and revision of the thrust curve(s) used for each relevant scenario(s).

- Losses
  - Wakes and other Turbine Interaction Effects: Report the wake model used for the wind farm efficiency assessment. In cases where more than one wake models are used (e.g. offshore), indicate briefly the method (e.g. ensemble) and list all relevant models.
  - WTG & BoP Availability: Indicate on what basis the loss has been assessed, i.e. whether is an assumption, a preliminary analysis, or a detailed site/project specific study.
  - Electrical Efficiency: Indicate on what basis the loss has been assessed, i.e. whether is an assumption, a preliminary analysis, or a detailed site/project specific study.
  - Environmental: Indicate on what basis the loss has been assessed, i.e. whether is an assumption, a preliminary analysis, or a detailed site/project specific study.
  - Curtailment / Operational Strategies: Indicate on what basis the loss has been assessed, i.e. whether is an assumption, a preliminary analysis, or a detailed site/project specific study.
  - Other: Replace 'Other' with the additional loss considered and indicate on what basis the loss has been assessed, i.e. whether is an assumption, a preliminary analysis, or a detailed site/project specific study.

7.0.7 Time-Evolving Losses and Uncertainties

In addition, long-term time evolution of either losses, uncertainties, or both may be included in the report. For example, availability losses might be assumed to be larger in the first year due to ramping up of the project's operations and maintenance procedures to a fully optimized state; and also potentially lowered availability in later years as maintenance events become more frequent. Performance, environmental, and curtailment losses and uncertainties may also include time-varying components. The report may include these results in the body or appendices, but they shall not be included in the normative reporting tables. The tables shall reflect averages for the project lifetime, unless clearly stated to be otherwise, or in the case of the P values for sub-periods (e.g., 1 year, 10 years), should reflect the average behaviour over a chosen period of that length from within the project lifetime. Average values shall be defined with respect to energy production (and not time), unless clearly stated to be otherwise.

7.1 Report Elements

As stated above, the ordering and numbering of the report elements is not normative, but inclusion of the elements themselves is normative, unless otherwise stated. The elements that are separately listed under subheadings "Text", "Figures", and "Tables" do not necessarily have to be in the format implied by the subheading, so long as the information intended by the normative element is conveyed (e.g., an item under "Figures" could be presented as a Table).

7.1.0 Executive Summary

The executive summary shall summarize the primary task description, the conclusions of the analysis and explicitly state any deviations from this standard. It should typically be 1-2 pages in length. The precise content of the text of the executive summary is not normative, with the exception that there shall be no new information included that has not been described and substantiated within the main report.

7.1.1 IEC Summary Tables

Within or immediately following the Executive Summary is a sensible and appropriate (though not normative) location for the normative IEC summary tables described in section 3.1. Alternatively, these could be presented in an appropriately named section of the body of the report, or in an Appendix. Regardless of where they appear, they should be clearly labelled "IEC Summary Tables".

7.1.2 Introduction

An introductory section is not normative but is included here as it often appears in energy yield assessment reports. Elements in the introduction may include the naming of the analyst, client, and project; brief descriptions of the project location, size, and turbine technology; and brief descriptions of the main objective of the analysis and the methods employed.

7.1.3 Site Description

The report shall include a description of the site, with the following elements.

- Text:
  - The names of the client and project.
  - A description of the geographic location. This should include the name of the nearest city or town, and the distance and direction of the project to that location; and the country and local administrative unit (state, province, county, district, and/or township) in which project is located. Provide the greatest degree of specificity possible for the local administrative unit.
  - A description of terrain, including degree of complexity of the project terrain, range of elevations for the project turbines, and significant nearby terrain features outside of the project.
  - A description of land cover, including vegetation types, trees and forestry, spatial variations in land cover, distance to sea or other large water bodies (where relevant), distance to shore (if offshore), and structures. Also describe any known or expected changes or trends in land cover (e.g. deforestation or forest growth).
  - Source of information, specifically whether from Client or from a Site Visit. In cases where a site visit has been performed, specific findings shall be addressed and/or depicted. Conversely where a site visit has not been carried out, the reasons for not doing so shall be stated, unless the reason is obvious, i.e. offshore.
- Figures:
  - A regional-scale map (recommended). As guidance, the map should cover an area roughly 400 km x 400 km, though potentially larger for offshore projects if needed to show surrounding coast lines; and potentially smaller for onshore projects if the wind farm is small or located in small countries or densely populated regions. This map should include roads, municipalities, national and state or province boundaries, and water bodies. It may include shaded relief or elevation contours if the project is located within or near complex terrain. It shall include a box or polygon depicting the project location, as well as boxes or polygons depicting present or future external projects considered in the analysis. It shall also show locations of long-term reference sites considered in the analysis.
  - A project-scale map (slightly larger than the bounds of the project). This map shall depict roads, municipalities, water bodies, and other local features of note. It shall show either shaded relief or elevation contours if the project is located within or near complex terrain. It shall include locations of project turbines and on-site measurement stations.
  - Photographs taken during the site visit of panoramic views of the site.
- Tables:
  - A table with project turbine parameters, including:
    - Project total nameplate capacity (MW)
    - Number of turbines
    - Turbine model(s)

        - Turbine rated power(s) (MW)
        - Turbine hub height(s) (m)
        - Turbine rotor diameter(s) (m)
        - Turbine IEC class
    - A table of turbine-specific parameters, see below.
        - Turbine ID
        - Turbine coordinates (easting, northing, and zone, in UTM projection with WGS84 datum); the turbine coordinates can additionally be presented in a local coordinate system, but UTM coordinates must be provided.
        - Turbine model(s)
        - Turbine elevation above mean sea level (m)

Note: If there are multiple scenarios being considered, and the turbine layout is a differentiator of the different scenarios, the layout specified in the above table shall be given a "layout identifier", which shall be used in the IEC table entitled "Scenario Comparison".

IEC Table G: Windfarm Layout for Scenario A

Turbine ID	Coordinates			Option for other coordinate systems	Elevation	Wind Turbine Model	Other Differentiator(s)
	UTM Zone	Easting	Northing				
1							
2							
3							
…							

7.1.4 Measurement Campaign

With regard to the measurement campaign, the following elements shall be included.

- Text:
    - A brief summary of what was confirmed during the site visit (if conducted), and by what methods.
    - Notes on maintenance or changes to measurement station configurations.
    - Boom orientation discrepancies: Differences between commissioning documents, site visit, and/or tower shadow analysis.
    - Major data gaps within the period of record for each measurement station.
    - Waking of measurement station
    - Any other issues that affect the use or exclusion of measurement station data.
    - Commentary on the general adequacy of the met campaign for the considered turbine layout, with specific attention to:
        - period of record
        - types and maximum heights of measurement stations

        - number and spatial coverage of measurement stations, including maximum distance from any project turbine to a measurement station

- Figures:
    - Photograph(s) of all measurement stations, if a site visit was conducted. For met masts, photograph(s) shall include the entire vertical extent of the mast, and depict tower type, guy wires, and instrument booms.
    - Photographs of views from measurement stations to at least the 4 cardinal directions, if a site visit was conducted.
- Tables:
    - For each measurement station:
        - Measurement station ID
        - Coordinates (easting, northing, and zone, in UTM projection with WGS84 datum)
        - Elevation
        - POR
        - Measurement time interval
        - Statistical parameters provided (mean, std. dev., max, min)
        - Data recovery summary, by month, see
        - Specifically for a meteorological mast:
            - Mast type (lattice, tubular, communication, etc.)
            - Data logger model, sampling interval in seconds, and averaging period in minutes
            - For each height
                - Boom orientation(s) and length(s)
            - For each sensor
                - Height
                - Sensor type: anemometer (cup, sonic, or prop and vane); vane; temperature; pressure; relative humidity
                - Sensor manufacturer, model, and serial number
                - Sensor class (for anemometers)
                - IEC classification (for anemometers)
                - Transfer function used (consensus or calibrated)
                - Calibration certificate copy (including, but not limited to certification number, date, wind tunnel, certifier)
            - Commentary on compliance with IEC 61400-12-1 and 61400-50-1
        - Specifically for an RSD:
            - Sensor manufacturer, model, and serial number
            - Parameters measured
            - Reporting heights
            - Compliance with IEC 61400-12-1, 61400-50-2, and 61400-50-4
            - Compliance with manufacturer’s siting guidelines, in relation to terrain features, obstacles, and signal propagation properties if relevant
            - Calibration report reference (including, but not limited to certification number, date, location, certifier)

IEC Table H: Measurement Campaign Data Recovery Rate

Instrument	LiDAR	LiDAR	LiDAR	Other

Height	40 m	100 m	150 m	
Jan ‘20				
Feb ‘20				
Mar ‘20				
….				

7.1.5 Measurement Data: Quality Control and Processing

With regard to the quality control of measurement data, the following elements shall be included.

- Text:
  - Description of the checks performed on the measurement data, which may result in flagging for exclusion (e.g., icing, tower shadow, sensor degradation for met masts; or precipitation, etc.). The following specific points shall be included:
    - Major data gaps, prior to filtering, within the period of record for each measurement station.
    - Description of automatic data-rejection rules applied, consequent reduction in data coverage, and approximate time periods most affected (e.g. 21 h between 2018-01-01 until 2018-02-28).
    - Manual data-rejection and approximate time periods affected.
    - Any other issues that result in exclusion of measurement data.
  - Description of any correction methods applied to erroneous data (rather than flagging for exclusion). This would include:
    - Corrections applied to vane measurements found to have an offset error
    - Time shifts to correct for incorrect initiation of the data logger(s)
    - Flow curvature corrections applied to RSD measurements (including flow model and correction methodology used)
    - Treatment of data from waked measurement stations, including treated sector(s) and wake model employed
  - Description of the method for combining redundant sensors on a met mast.
  - Conclusion of the final data integrity and quality together with description and motivation for the primary data set(s) to be used.
- Tables:
  - A list of major periods of erroneous and/or missing data
  - Any data-rejection criteria, including automatic filtering rules, that are more amenable to tabular representation. These can be presented in a table rather than in text as listed above.
  - Overall data recovery rate, separated by measurement level and/or instrument of the original data set, after processing (rejection and corrections).

7.1.6 Wind Resource Characteristics at Measurement Station Height

After measurement data have been fully quality controlled, the report shall present information, figures, and tables summarizing the wind resource at primary sensor height for each measurement station. For both met masts and RSD, “primary sensor height” refers to the highest reported height that is at or below the turbine hub height. The following elements shall be included.

- Figures:
  - Wind rose from primary sensor height wind direction for each measurement station, with no fewer than 12 sectors displayed.

- Tables:
  - For each measurement station, a table of all months in the POR, detailing sensor heights utilised, covering mean wind speed, wind speed data recovery percentage, wind direction, and wind direction data recovery rate. Final line should show same quantities for the entire POR.
  - Ambient TI value (as defined in IEC 61400-1 Ed. 4) at primary sensor height for each measurement station.
  - If concurrent data is available at the same height for all or some of the measurement stations, it is recommended, though not required, to present wind speed, wind direction, wind shear and ambient TI statistics for each of the measurement stations, at the common sensor height, over the concurrent data period

7.1.7 Data Reconstruction / Temporal Extension

Once the data has been processed such that the measurements are considered to not contain a seasonal bias and be representative of an annual period, the following elements should be included. It is noted that this may be achieved by considering "mean of monthly means", curtailing the dataset period and/or extending measurements using other measurements on the same measurement station or from other measurement stations. Where there is overlap between the reporting requirements provided in Section 3.2.7 that information can be provided at either the measured wind characteristics stage (Section 3.2.7) or after data reconstruction/temporal extension (Section 3.2.8).

- Text:
  - Descriptions of any methods used to ensure that the on-site measurements are representative of an annual period.
  - Informative: Description of method to combine measured temperature, pressure, and humidity to produce an air density estimate valid at the temperature measurement height. This shall include the assumptions or calculations in extrapolating pressure and/or humidity from their respective sensor heights to the temperature sensor height, and assumptions made or alternate data sources used if either pressure or humidity are not available from the measurement station.
  - For RSD, where ambient TI is analysed within the assessment, a description of the method to derive "cup anemometer-equivalent" TI, and the resultant ambient TI value (as defined in IEC 61400-1 Ed. 3) at the highest reported height at or below the turbine hub height. If no "cup anemometer-equivalent" TI method is applied, then a description of the representativeness of the data relative to cup anemometer TI levels should be provided.
- Figures:
  - Histogram of primary sensor height wind speed for each measurement station, with bin width no greater than 1.0 m s^{-1}.
  - Diurnal cycle of primary sensor height wind speed for each measurement station.
  - Seasonal cycle of primary sensor height wind speed for each measurement station.
  - Wind and energy rose from annualized primary sensor height wind direction for each measurement station, with no fewer than 12 sectors displayed.
- Tables:
  - Where data synthesis has been conducted information should be provided on the quality of correlation between datasets used and the relationship established. For example of a 30° sectorwise linear relationship is used then the R^2 quality of correlation and the slope and offset values associated with the linear relationship will be provided for each 30° sector direction.
  - For each measurement station, a table of all months in the POR, with columns for primary sensor height mean wind speed, wind speed data recovery, wind direction, and wind direction data recovery rate. Final line should show same quantities for the entire POR.
  - Reference TI value (as defined in IEC 61400-1 Ed. 3) at primary sensor height for each measurement station.
  - Weibull parameters at primary sensor height for each measurement station.
  - Mean air density at the temperature sensor height that is closest to the primary sensor height for each measurement station.

    - Informative: 12 month x 24 hour table of primary sensor height wind speed for each measurement station.

7.1.8 Historical Wind Resource

The historical wind resource section describes the reference datasets and methods used to place the short-term on-site data into the context of the long-term historical climate at the site. With regard to the analysis of historical wind resource, the following elements shall be included.

- Text:
    - For each reference source considered:
        - Description of:
            - Site name and/or ID, POR, distance from project, parameters reported and height above ground of the respective parameters
            - Known sensor or data set construction issues that potentially affect data consistency over time
        - Discussions specific to three types of reference sources:
            - Measurement site
                - Observing network to which reference measurement station belongs, and overseeing organization
                - Heights and types of sensors
                - Exposure and obstacles that might affect wind measurements
                - Instrument changes at site
                - Whether site has been visited and, if so, what was confirmed in visit
            - Reanalysis data set
                - Names of reanalysis data set and producing organization, and reference to overview article in the scientific literature
                - Horizontal resolution in km
                - Relevant available parameters and height levels
                - Time frequency
                - Whether a nodal point record, or spatially interpolated record, was acquired
            - Virtual meteorological mast
                - Name of virtual meteorological data set, producing organization, and reference to overview article in the scientific literature
                - Outer nest(s) and forcing used
                    - Underlying reanalysis dataset
                    - Nudging method
                - Mesoscale model used: Name, Version, Source
                    - PBL schemes/parameterizations chosen
                - Domain setup
                    - Horizontal grid spacing in km; (Δx_{eff} , if known)
                    - Domain size
                    - Number of nests, nesting scheme
                - Surface data used
                    - Orography/DEM: N,V,S

        - Land-use/roughness: N,V,S; dynamic or static
        - Sea-surface temperature: N,V,S; dyn.or static
      - Relevant available parameters and height levels
      - Time step and output or averaging step/period
      - Length of model run(s), in years
  - Discussion of reference source selection/rejection process, including method used to combine reference sources into an ensemble if applicable, and what averaging time scale was used for the correlation analysis (hourly or daily are recommended).
  - Discussion of reference source data filtering and quality control procedures
  - Description of method to develop mathematical relationships between reference source meteorological data and on-site measurement station primary sensor height wind speed. This description should include the motivation for the method chosen, with emphasis on uncertainty reduction; and how the relationships are applied to create a historical wind resource (e.g. by a Measure-Correlate-Predict method).
  - For each measurement station:
    - Result of the selection/rejection process for each reference source
    - Relationships obtained between chosen reference source meteorological data and on-site measurement station primary sensor height wind speed, and how these are applied to create a historical wind resource [e.g., by a MCP (Measure-Correlate-Predict) method].
  - Informative: Text may include descriptions of statistical tests applied to detect trends or inhomogeneity in the reference wind speed record.
  - Description of method to extent the measured temperature, pressure, and humidity to produce an air density estimate representative of the historical period that is valid at the WTG hub height. This shall include the assumptions or calculations in extrapolating pressure and/or humidity from their respective sensor heights to the hub height, and assumptions made or alternate data sources used if either pressure or humidity are not available from the measurement station.
  -
- Figures:
  - Locations of reference sources in regional map described in section 3.2.4. This is not necessary for virtual meteorological mast reference sources considered to be collocated with on-site measurement stations.
  - Time series of annual mean wind speed for all considered reference sources, overlaid on a single plot. Note, these can be either unadjusted, or normalized in some way to improve comparability.
  - For each reference source, a scatter plot of reference versus measurement site daily or hourly mean primary sensor height wind speed
- Tables:
  - Reference source coordinates (easting, northing, and zone, in UTM projection with WGS84 datum)
  - R^2 values of reference versus measurement station primary sensor height daily or hourly mean wind speed for each reference source and measurement station (optionally could be stated in text or annotated on scatter plot).
  - Final long-term adjustment factor to convert site period annualized mean wind speed at measurement station to a long-term mean value. Note, it is acceptable to adjust the long-term reference time series to match the on-site data during the overlapping period, and perform the energy yield analysis on the referernce time series. However, care must be taken to ensure

that the resultant time series matches the on-site data in terms of distribution shape, seasonal and diurnal patterns, and wind rose. In either case, the adjustment factors should be presented.

Non-wind variables:

    - Interannual variability of energy yield due to interannual variability of temperature (via air density) is at least an order of magnitude smaller than that due to wind speed. Therefore the following information regarding historical variability of temperature are sufficient:
        - A description of long-term adjustment method for temperature at the temperature sensor height for each on-site measurement station that includes temperature.
        - A table of the reference source(s) chosen, the R^2 values of daily or hourly mean reference temperature with respect to on-site measurement station daily or hourly mean temperature, and the final relationship and LTC (long-term correction) obtained.

7.1.9 Vertical Extrapolation

The vertical extrapolation section of the report describes the process by which wind speed is extrapolated (or in some cases interpolated) vertically from sensor height(s) to the turbine hub height. With regard to the vertical extrapolation of wind speed, wind direction, air density, and standard deviation of wind speed from sensor height(s) to hub height at each measurement station, the following elements shall be included.

- Text:
    - Wind speed extrapolation method, if it differs from the method recommended in IEC 61400-15-2
        - i.e. windspeed, annual mean, seasonal mean or time-series etc., or Weibull parameters etc.
    - Method and result of extrapolation of air density to hub height
    - Method and result of extrapolation of wind direction to hub height

Method and result of extrapolation of standard deviation of wind speed to hub height

- Figures:
    - Informative: Repeat figures illustrating wind resource at primary sensor height (described in section 3.2.7), except using the values extrapolated to hub-height.
- Tables:
    - Table of annualized wind shear exponent to be used at each measurement station to extrapolate from primary sensor height to hub height. The table(s) should show values of wind shear exponent, binned according to whatever variable or variables the analyst considered most important to the energy yield calculation. These variables could include, but are not limited to, wind direction, wind speed, time of day, and/or time of year (season).
    - Typically, the wind shear values would be derived from a wind shear calculation over all sensor or measurement heights reported by the measurement station, under the assumption that the wind shear within the extrapolation layer is the same as the wind shear within the measured layer. However, if there is information indicating a different wind shear within the extrapolation layer is likely, this table should reflect that adjustment. Such information could come from other on-site measurement stations (either met mast or RSD) that measure higher than the top measurement height for the measurement station under consideration; or from wind flow models that include meteorological processes that govern changes in wind shear with height.
    - The reasoning and data sources for such adjustments should be described.
    - If extrapolating Weibull parameters, then table of each of the WAsP, extrapolation or stability parameters should be reported

In addition, the following elements may be included:

  - Informative: Repeat tables illustrating wind resource at primary sensor height (described in section 3.2.7), except using the values extrapolated to hub-height
  - Description and results of cross-prediction, if three or more measurement heights are available.

7.1.10 Operational Data

In the case that operational data from reference turbines were used as a wind measurement strategy, the following information shall be included in the report:

- Text and/or tables:
  - Site and distance between future project and the reference wind turbines
  - Brief description of the reference site (elevation, complexity classification, orography, roughness, obstacles, neighboring wind farms).
  - Description of the comparability of the reference wind turbine and regional representativeness of the wind data used.
  - Wind turbine model, hub height, and coordinates.
  - Power curve and thrust coefficients data taken into consideration.
  - Type and source of operating data, period of record, and temporal resolution.
  - Description of the data quality procedure adopted (detection and elimination of erroneous data).
  - If the operation was subjected to constraints (grid and/or turbine availability, changing operating modes, bats, shading, sector management, etc.), the description of the constraints correction must be included.
  - Documentation if any changes in wind farm wake effects happened within the evaluated period of record of the reference wind turbines.
  - Description of the adopted procedure for long-term correction of the reference wind turbine yield data and the long-term data used (source or type and period of record).
  - Results of the comparison between the long-term energy yield of the reference wind turbine and the energy yield calculated for the reference wind turbine at the reference site.
  - Verifications and validations framework adopted.

7.1.11 Horizontal Extrapolation

The horizontal extrapolation section describes the wind flow modelling used to extend measured wind speeds horizontally across the project domain to turbine locations. With regard to the horizontal extrapolation of wind resource, the following elements shall be included.

- Text and/or tables:
  - Description of model(s) used
    - Software name and version
    - Type of model (linear flow, CFD-RANS, mesoscale NWP model, mass-conserving model, combinations there of, etc.)
    - Setting of key configuration choices that are commonly reported for the model used
    - Horizontal and vertical grid spacing (if applicable)
    - Length of simulations (for time-dependent models) or time to convergence (for steady-state models such as CFD)
    - Limitations of model (maximum slope, thermal flows, etc.)
    - Site-specific model settings to better match measured wind characteristics (e.g., the vertical wind profile)

        - Literature references describing model, especially for applications similar to the project being analyzed.
    - Sources of high-resolution terrain and land cover data
    - Description and results of cross-prediction experiment, if two or more on-site measurement stations are available.
    - Spatial assignment or weighting of measurement stations to turbine locations
    - Method and result of horizontally extrapolating hub-height air density from measurement stations to turbine locations, including elevation adjustment.
- Figures:
    - Model domain (can be combined with maps described in section 3.2.4)

7.1.12 Project Wind Resource Characteristics at Hub Height

With regard to the final wind resource characteristics at turbines and for the project average, the following elements shall be included.

- Text:
    - Project-average long-term mean wind speed
    - Project-average long-term mean air density
- Figures:
    - Annual mean wind speed contour/heat map
- Tables:
    - Mean windspeed summary table, with inclusion and sequence as applicable to the analysis method selected:
        - Measurement campaign
        - Following synthesis
        - Following long-term adjustment
        - Following vertical extrapolation
        - Following horizontal extrapolation, to a characteristic location in the windfarm
    - 12 month x 24 hour table of project-average long-term mean wind speed, if there is significant seasonal and diurnal variability.
    - Seasonal long-term mean wind speed if there is significant seasonal variability
    - Diurnal long-term mean wind speed if there is significant diurnal variability
    - Turbine-specific quantities (Note: these table elements can be combined with the turbine-specific parameters table described in section 3.2.4)
        - Long-term mean wind speed
            - Note: this should be unwaked wind speed. Additionally, a long-term mean waked wind speed may be included as a separate column
        - Long-term mean air density
        - Reference TI (as defined in IEC 61400-1 Ed. 3)

7.1.13 Gross Energy

With regard to Gross Energy, the following elements shall be included.

- Text:
    - Statement of the software used to calculate the Gross Energy, including:

        - Version number
        - relevant parameter settings
    - Statement regarding WTG power curve used to calculate the Gross Energy, together with
        - identification references,
        - relevant applicable external conditions, including:
        - air density,
        - wind shear,
        - turbulence intensity,
        - operational temperature range
        - power boost, de-rating and/or curtailment with any associated parameter conditions.
        - point of measurement or definition; this is typically the low voltage side of the WTG transformer, however this could also be the high voltage side of the WTG transformer, or elsewhere.
        - method of derivation, i.e. calculated or measured; if calculated, option to present details of any relevant verification or degree of design maturation
        - details of any special operating conditions or operational modes.
    - Statement regarding WTG power coefficient curve used to calculate the Gross Energy can be provided; no further commentary required if this is calculated directly from the WTG power curve using the rotor diameter (add IEC reference)
    - Statement regarding WTG thrust curve used to calculate the Gross Energy, together with
        - identification references,
        - relevant applicable external conditions, including:
        - air density,
        - wind shear,
        - turbulence intensity,
        - method of derivation, i.e. calculated or measured; if calculated, option to present details of any relevant verification or degree of design maturation
        - details of any special operating conditions or operational modes
- Figures/Tables:
    - For the three curves listed below, values at regular wind speed intervals (minimum interval of 1.0 m/s) shall be presented in tables. It is recommended but not required that graphs of the curves also be provided as figures,
        - WTG power curve
        - WTG power coefficient curve
        - WTG thrust curve

7.1.14 Plant Performance and Net Energy Yield

With regard to Plant Performance and Net Energy Yield all potential loss categories should be stated, along with whether or not they were considered. Any categories which are not included can be stated to be “not applicable” or “not considered”.

The methodology used to derive the loss associated with each category should be detailed. This should include the general approach such as statistical methods, timeseries methods and/or empirical information. For each method, more details should be provided such as the source and temporal resolution of the data.

The following elements shall be included as an introduction and overview:

- Text:
    - Details for all relevant loss categories shall be included, according to the sub-headings listed in this section
    - Where the impacts of loss categories are excluded, the reasons for the exclusions shall be given
    - Where losses differ in the first year(s) or in later year(s), this shall be noted.

7.1.14.0 Wake, Blockage, and Other Turbine-Atmosphere Interaction Effects

With regard to Wake Effects, the following elements shall be included:

- Text:
    - Statement of the wake model(s) used, including relevant parameter settings and details of validation for the current purposes
    - If relevant, statement regarding methods for determining internal, external and future wakes, by combining results from individual wake models, together with a justification for any differences
    - Statement of justification regarding any methods used to correct the calculated wake losses, for example where the original wake methods have been judged to be insufficient for the current purposes; details of validation for the use of the correction for the current purposes.
    - Statement summarising the build-out of the windfarms that underly the future wakes scenario(s)
- Tables:
    - Where more than one wake model is used, a table summarising the approach taken shall be included, encompassing at a minimum the following fields:
        - Application, i.e. internal, external
        - Wake model name
        - Relevant Parameter Settings
    - Wake Efficiency (if applicable)
    - Ensemble Weighting (if applicable)
    - If more than one approach is used for calculating different aspects of the wake losses, such as internal and external, then this shall be described in one or more Tables
    - Summary of windfarms included within the future wakes scenario(s); should include a brief comment regarding the stage of development, i.e. likelihood of being constructed, likelihood of the timeframe being met and likelihood of capacity and WTG details being changed
        - Windfarm name
        - Generating capacity, including location where capacity is specified or metered
        - WTG numbers
        - WTG description
        - Anticipated Timeframe
        - Development stage, i.e. speculative, conceptual, final design etc.

A table of total wake losses (internal, external, and future) shall be reported for each WTG. The turbine-specific wake losses can be combined with other turbine-specific tables described in sections 3.2.4 and 3.2.11.

The following group of sub-categories relate to Availability.

7.1.14.1 Turbine Availability

With regard to Turbine Availability, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Turbine Availability, including a description of how time-based availability has been converted in to an energy-based availability value, if relevant, and the rationale for the values chosen
- Figures/Tables :
    - Where the WTG availability differs over the years; this shall be presented in a Table, together with the value selected for use in the main calculations. The yearly variability may also be depicted as a graph in a figure.
    - Comments supporting the Turbine availability level/profile can be provided for information and would be expected to refer to Turbine availability elements as defined in IEC 61400-26 Ed 1 (2019) [REF].

7.1.14.2 BOP Availability

With regard to BOP Availability, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale for the assumptions for the BOP Availability
    - Where BOP Availability has a significant impact on the Net Energy Yield, i.e. 1% or more, a statement of the breakdown of the source of availability may be included
- Tables:
    - Where BOP Availability has a significant impact on the Net Energy Yield, i.e. 1% or more, a summary table may be included, identifying major sub-categories such as:
        - WTG Transformer
        - Windfarm array Cables / Overhead Lines
        - Windfarm Substation, i.e. located within the windfarm
        - Export Cable / Overhead Line
        - Windfarm Grid Substation, i.e. located adjacent to the grid connection
        - Other electrical infrastructure, such as reactive compensation substation
    - Comments, including brief reference to source, methodology and the rationale for the assumptions

7.1.14.3 Grid Availability

With regard to Grid Availability, the following elements shall be included, if available:

- Text:
    - Statement of the source and the rationale for the assumptions for the Grid Availability; the following details may be included:
    - Type of grid: transmission, distribution or local
    - Voltage level
    - Degree and details of any redundancie

7.1.14.4 Electrical Efficiency

With regard to Electrical Efficiency, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale for the assumptions for the Electrical Efficiency
    - Where Electrical Efficiency has a significant impact on the Net Energy Yield, i.e. 1% or more, a statement of the breakdown of the source of efficiency shall be included, if this information is available.
    - Statement of where the project will be metered, typically either on the low-voltage (project) side of the project substation, or on the high-voltage (grid) side.

- Tables:
    - Where Electrical Efficiency has a significant impact on the Net Energy Yield, i.e. 1% or more, a summary table may be included identifying major sub-categories such as:
        - WTG Transformer
        - Windfarm array Cables / Overhead Lines
        - Windfarm Substation, i.e. located within the windfarm
        - Export Cable / Overhead Line
        - Windfarm Grid Substation, i.e. located adjacent to the grid connection
        - Other electrical infrastructure, such as reactive compensation substation
    - Comments, including brief reference to source, methodology and the rationale for the assumptions

7.1.14.5 Facility Parasitic Consumption

With regard to Facility Parasitic Consumption, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Facility Parasitic Consumption. The statement shall include the rationale for excluding this loss, if applicable. If the project is net-metered, the loss is typically included in the energy yield assessment; whereas if there is a separate meter for inbound power, this loss is typically not included in the energy yield assessment, but rather, becomes part of the windfarm's O&M costs.

7.1.14.6 Sub-optimal Performance

With regard to Sub-optimal Performance, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Sub-optimal Performance

7.1.14.7 Generic Power Curve Adjustment

With regard to Generic Power Curve Adjustment, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Generic Power Curve Adjustment
    - Where a measured power curve is used and the windspeed was measured within the induction zone, or a calculated power curve is used, and this is defined as being equivalent such a measured power curve, this sub-category may include a correction for measuring the windspeed within the induction zone

7.1.14.8 Site-specific Power Curve Adjustment

With regard to Site-specific Power Curve Adjustment, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Site-specific Power Curve Adjustment, including:
        - air density,
        - wind shear,
        - turbulence intensity,

7.1.14.9 High Wind Hysteresis

With regard to High Wind Hysteresis, the following elements shall be included:

- Text:
  - Statement of the source, methodology and the rationale of the assumptions for the High Wind Hysteresis, including:
    - Cut-in, cut-out and ramping windspeeds activation levels

The following group of sub-categories relate to Environmental Losses.

7.1.14.10 Icing

With regard to Icing, the following elements shall be included:

- Text:
  - Statement of the source, methodology and the rationale of the assumptions for the Icing, including:
    - Frequency of instrument icing observed at on-site met towers,
  - Use of generic regional assumptions versus temperature data sources

7.1.14.11 Degradation

With regard to Degradation, the following elements shall be included:

- Text:
  - Statement of the source, methodology and the rationale of the assumptions for the Degradation, including:
    - Components affected:
    - Blades
    - Drive-train
    - Driver for degradation, such as age, insects, dirt, salt, deterioration
    - Recovery, such as scheduled maintenance, rain cleaning

7.1.14.12 Environmental Loss (External conditions)

With regard to Environmental Loss (External conditions), the following elements shall be included if appropriate for the losses applied:

- Text:
  - Statement of the source, methodology and the rationale of the assumptions for the Environmental Loss (External conditions), including:
    - Presence of migrating birds or bats

7.1.14.13 Exposure Changes

With regard to Exposure Changes, the following elements shall be included:

- Text:
  - Statement of the source, methodology and the rationale of the assumptions for the Exposure Changes, including:
    - Tree growth and felling

7.1.14.14 Load Curtailment

With regard to Load Curtailment and the sub-categories of Curtailment and Operational Strategies Losses, the following elements shall be included:

- Text:

    - Statement of the source, methodology and the rationale of the assumptions for the Load Curtailment, including:
        - Wind sector management

7.1.14.15 Grid Curtailment

With regard to Grid Curtailment, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Grid Curtailment, including:
        - Grid constraints (caused by capacity limits in the local or regional grid)
        - Grid curtailments (caused by capacity limits in the national grid)
        - Whether the grid limitation is being applied as a static or dynamic curtailment.

7.1.14.16 Environmental / Permit Curtailment

With regard to Environmental / Permit Curtailment, the following elements shall be included:

- Text:
    - Statement of the source, methodology and the rationale of the assumptions for the Environmental / Permit Curtailment, including:
        - Noise management

7.1.14.17 Operational Strategies

With regard to Operational Strategies, the following elements shall be included:

- Text:
    - Statement of the source and the rationale of the assumptions for the Operational Strategies, including:
        - Methodology for determining the loss
        - Extent of application

7.1.15 Uncertainty Analysis

With regard to Uncertainty Analysis, the following elements shall be included:

- Text:
    - a description of the uncertainty associated with each individual adjustment and loss sub-category shall be reported
    - methodology for determining the uncertainty shall be presented
    - in general, the uncertainty should be justified and should reflect the supporting evidence; this could be of the form of:
        - assessment from first principles, based on statistical theory and relevant evidence bases
        - benchmarking of historical performance at representative operational windfarm projects
    - where the methodology reverts to common practice, this shall be clearly stated.
    - If no benchmarking has been undertaken or no other evidence is available to support the assumptions, a conservative approach to uncertainty shall be utilised.
    - Methodology for determining the wind-to-energy sensitivity ratio

- applicability of any evidence base to the current assessment
- Methodology for Combining Uncertainty categories

The uncertainty analysis shall focus on the categories that have the largest impact on the overall energy yield uncertainty, in terms of the uncertainty itself as well as the general confidence in the approach and opportunity to improve the methodology.

Additional guidance is provided below for selected sub-categories.

7.1.15.0 On-site Measurement

With regard to assessing the uncertainty of On-site Measurement, in additional to the general principals outlined above, the following shall be reported:

- Text:
  - Suitability of measurement technology for the particular site
  - Data coverage, including availability and benefits from redundancy

7.1.15.1 Vertical Extrapolation

With regard to assessing the uncertainty of Vertical Extrapolation, in additional to the general principals outlined above, the following shall be reported:

- Text:
  - Presence of measurement biases, such as mast shadow, that could impact the uncertainty propagation

7.1.15.2 Wake Effects

With regard to assessing the uncertainty of Wake Effects, in additional to the general principals outlined above, the following shall be reported:

- Text:
  - Wind climate characteristics, in particular stability
  - Lower rotor blade tip clearance, where this is lower than utilised in wake benchmarking studies
  - An example would be offshore where lower blade tip heights have become progressively proportionally smaller over the years

7.1.15.3 Turbine Availability

With regard to assessing the uncertainty of Turbine Availability, in additional to the general principals outlined above, the following shall be reported:

- Text:
  - Experience and commitment of the WTG supplier in this market or sector
  - Maturity of the WTG model; if a recently launched model, then extent of technical commonality with existing models
  - Maturity of operation and maintenance strategy
  - Robustness and adaptability of operation and maintenance strategy
  - Level of detail considered within availability studies
  - Terms in contractual availability warranties (definitions and limitations/compensation caps)

7.1.16 Compliance to Standards

With regard to Compliance to Standards, the following elements shall be included.

- Text:

    - Relevant standards: These would include, at a minimum, the standard described herein (IEC 61400-15-2). It could also include other international or national standards, such as MeasNet [reference] or FGW TR6 [reference].
    - Description of reasons for non-compliance (can be in text or table)
- Tables:
    - Summary of all issues of non-compliance and anticipated impact on energy production as well as the associated uncertainty

7.1.17 Conclusions and Recommendations

With regard to Conclusions and Recommendations, the following elements shall be included.

- Text:
    - Main conclusions highlighting primary conclusions as well as unusual characteristics of the work
    - Recommendations for measured that could be taken to reduce the uncertainty associated with the energy yield assessment can be provided, such as additional measurements, data sources and analysis that would have a material impact on the main results and / or the associated uncertainty
- Tables:
    - IEC summary tables as described in section 7.1.1

In general, a well written Conclusions and Recommendations section should be no longer than two or three pages.

7.1.18 Appendices

The report may include Appendices, covering information additional to that presented in the main body of the report. Examples of material that is suited for appendices includes:

- Calibration certificates
- Installation reports
- Verification and validation reports
- Supporting analyses, providing additional detail than is usually in a typical main report

Only material that is directly relevant and critical to the understanding of the energy yield assessment report should be included. All other material can be included in the form of references.

7.2 Wind Energy Yield Assessment Digital Exchange Format (EYA DEF)

The wind Energy Yield Assessment Digital Exchange Format (EYA DEF) organises key reporting elements into a hierarchical data model in the form of a JSON Schema. The JSON Schema provides a standard protocol for data exchange, so that producers and consumers of the data have a common and clear definition of the data structure and meaning of data items. The JSON Schema also facilitates data validation, so that a receiver of a wind EYA DEF JSON document can automatically validate that the data are fully compliant with the data model specification.

A JSON document that is compliant with wind EYA DEF JSON Schema shall be prepared and distributed alongside the main written report. The compliance of a JSON document with the wind EYA DEF JSON Schema can be checked using any standard JSON Schema validation tool.

This standard is concerned only with the content of the digital exchange format and imposes no requirements with regards to technology for data transmission and storage, or protocols for digital signatures and encryption. In the simplest form of data exchange, an EYA DEF document may simply be transmitted as a JSON text data file attached to an email together with the main written report. It is however expected that secure APIs for EYA DEF documents will be developed to automate the data exchange process and provide comprehensive functionality to ensure data security and integrity. The user of this standard should adopt appropriate best practices to ensure data security and integrity in transmission and storage of wind EYA DEF data. Adherence to such best practices will minimise the risk for data manipulation or unauthorised access. Encoding and compression of the data should be specified at the point of access (for example in the API specification).

The wind EYA DEF JSON Schema is available at the following URL:

> https://raw.githubusercontent.com/IEC-61400-15/eya_def/main/json_schema/iec_61400-15-2_eya_def.schema.json.

Examples, tools, documentation and other material related to the wind EYA DEF are available in the GitHub repository at the following URL:

> https://github.com/IEC-61400-15/eya_def.

7.2.0 Aims and use cases

The wind EYA DEF aims to facilitate:

– data sharing with a wider range of stakeholders in an automated fashion;

– comparison of EYA results from different parties, for example for example from different third-party consultants;

– integration with other systems, such as financial model software; and

– automated generation of reporting tables.

For example, if a project developer receives EYA DEF JSON documents from its independent consultants, the data can immediately be loaded into the relevant internal databases and applications, and the results compared between the different consultants and with internal findings. Then the developer can share the wind EYA DEF JSON documents with lenders, investors and any other financial institutions who require the information to evaluate the project. They in turn will all be able to pull the data they need into the relevant applications without the requirement for any manual data processing. The same goes for other project stakeholders who require EYA reporting data.

It is also expected that the EYA DEF data models will provide a helpful reference for companies developing energy yield assessment software. Whilst the data models used internally in such software of course do not need to mirror the EYA DEF in order to be able to export results in EYA DEF format, the EYA DEF data models may in some circumstances prove useful and avoid the need to completely new design new data models.

7.2.1 Data model overview

7.2.2 Tools

It is expected that the wind EYA DEF will support the creation of tools for processing, validating (beyond the declarative validation inherent in the JSON Schema), visualising, reporting and comparing energy yield assessment data in a standardised manner. Such tools are anticipated to help facilitate the adoption and ease of use of the EYA DEF. This standard imposes no requirements on the use of any specific tools.

7.3 Table of Contents for an Energy Yield Assessment Report (informative)

As a guide, the following table of contents may be used to structure the energy yield assessment report. While the section and subsection structuring and numbering presented here are informative, the elements described throughout the body of section 3 ("Reporting") are normative, except where explicitly indicated as informative.

Executive Summary

- IEC Summary Tables
  - Scenario Comparison
  - P50 Annual Energy Production
  - Uncertainty and Probability of Exceedance Values
  - Categorical Wind Speed-based Uncertainties
  - Categorical Plant Performance Losses and Uncertainties
- Introduction
- Site Description
- Measurement Campaign
- Measurement Data Quality Control
- Wind Resource Characteristics at Measurement Station Height
- Historical Wind Resource
- Project Wind Resource Characteristics at Hub Height
- Horizontal Extrapolation
- Gross Energy
- Plant Performance and Net Energy Yield
- Uncertainty Analysis
- Compliance to Standards
- Conclusions and Recommendations
- Appendices
  - Appendix A. Supplementary Information or Calculations
  - Appendix B. Measurement Installation and Calibration Documentation

7.4 Guidance and Examples for the IEC Summary Tables

8 Combining uncertainties

This section outlines the process of combining component uncertainties, towards calculating a single uncertainty estimate for predicted energy at a given site. The framework begins with simple combination of uncorrelated (independent) uncertainty components, but also allows for additional uncertainty due to cross-component correlations. Further, a basic statistical method is given for combination of uncertainties from multiple measurement sources; this allows for de-correlation of individual component uncertainties across masts, accounting for the resultant reduction in uncertainty.

Refer to Annex A for details on the application and use of the accompanying Excel spreadsheet that combines all uncertainties. The accompanying spreadsheet can be downloaded from the URL: https://www.iec.ch/tc88/supportingdocuments

8.0 Description of uncertainty combination

Unless otherwise specified, all uncertainty components and subcomponents are assumed to be normally distributed[1] (Gaussian); subsequently the uncertainties quoted correspond to standard deviations, unless otherwise noted.

Uncertainties are expressed as dimensionless quantities (e.g., as percentages or decimals), in terms of either mean wind speed or energy. A speed-to-energy “sensitivity factor” s_{UE} is used to relate uncertainty in mean wind speed $\sigma_{\mathrm{tot},U}$ to uncertainty in energy $\sigma_{\mathrm{tot},E}$, simply as $\sigma_{\mathrm{tot},E} = s_{UE}\sigma_{\mathrm{tot},U}$ (see Section 8.3 for more details).

Most generally, uncertainty components may be combined via,

[1] The assumed non-systematic random behavior corresponds to type “B” uncertainties in GUM (JCGM, 2008), i.e., derived with prior knowledge or model. Some uncertainty components might be labeled as type “A” in GUM (from data only) and are assumed also to be normally distributed. Exceptions to this shall be noted by the user/reporter of the uncertainty.

$$\sigma_{\text{total}} = \sqrt{\sum_i \left[\sigma_i^2 + \sum_{j \neq i} (\rho_{ij}\sigma_i\sigma_j) \right]} \tag{8-1}$$

Where:

σ_{total} is the total combined uncertainty, expressed as a percent of wind speed

σ_i, σ_j are the uncertainty components, expressed as a percent of wind speed

ρ_{ij} are the correlation coefficients for any given pair of uncertainty components, σ_i and σ_j, expressed as unitless values between 0 and 1

Equation (8-1) is consistent with the JCGM's Guide to the Expression of Uncertainty in Measurement, or "GUM" (JCGM, 2008). Each component corresponds to a different type: e.g., uncertainty in horizontal extrapolation, wind-speed measurement, long-term correction, etc.

8.1 Combination of component-uncertainties

Numerous uncertainty components are separately estimated for the different processes and parts of resource (energy-yield) assessment. Some of these also contain sub-components that have been combined into a single bulk component category estimate, which is given as input into the total uncertainty combination calculation. The list of inputs is found in Table 8-1 and Table 8-2.

A widespread, implicit assumption in the wind industry has been that uncertainty components are all uncorrelated. Under this assumption of independence all $\rho_{ij} = 0$, so that the total uncertainty shown in (1) simply reduces to

$$\sigma_{\text{total}} = \sqrt{\sum_i \sigma_i^2} \tag{8-2}$$

Where:

σ_{total} is the total combined uncertainty, expressed as a percent of wind speed

σ_i are the uncertainty components, expressed as a percent of wind speed

Equation (8-2) expresses the total uncertainty computed as the root-sum-of-the-squares (RSS) of all uncertainty components. This is the basis of the current edition standard, although the standard and associated calculation sheet permits the use of correlated error, computed using Equation (8-1).

However, there are elements of wind resource assessment which are linked, where the assumption of uncorrelated σ_i becomes invalid. For example, frequently, in the case of model-related uncertainties, the model depends upon wind speed input, which results in a nonzero correlation (ρ_{ij}) between the measurement uncertainty and the model uncertainty subcomponents. A common practice in the wind industry has been to ignore the correlations and assume $\rho_{ij} = 0$ for all $\{i, j\}$. Ignoring correlated error can result in significant error in the estimated uncertainty (potentially inflating or underestimating the uncertainty).

We further note that to avoid 'double-counting' *propagated* wind measurement uncertainty, it must be reported separately every time that it arises—to properly calculate the *excess* propagation.

8.2 Multiple measurement sources separated in space and practical combination of uncertainties

Just as there can be correlation between some uncertainty *components*, some of these components can become *spatially* <u>*de-*</u>*correlated* when being considered at points separated in space —as occurs when modelling wind resource based on multiple measurement masts. This contrasts with the common assumption that uncertainties can be treated as identical at all masts. Multiple masts are used to exploit such decorrelation.

Following common industrial wind practice, we begin simply by assuming that uncertainty components (types) are uncorrelated with each other, and that each component itself is fully correlated across mast locations (if multiple masts are used); then relevant cross-component correlations can be added if desired, and cross-mast decorrelations can be included if justified.

To exploit multiple mast data, cross-mast de-correlations for components (listed in Table 8-1) may be used with justification. For each uncertainty component (σ_i), if multiple masts exist, then the uncertainty components per mast *m* and *n* ($\sigma_{i,m}$ or $\sigma_{i,n}$) are added across all mast pairs, analogous to Equation (8-1),

$$\sigma_i = \sqrt{\sum_m \left[\left(w_m \sigma_{i,m}\right)^2 + \sum_{n>m} \left(c_{mn} w_m w_n \sigma_{i,m} \sigma_{i,n}\right) \right]} \qquad (8\text{-}3)$$

Where:

σ_i is the cross-mast uncertainty for component *i*, expressed as a percent of wind speed

$\sigma_{i,m}$ or $\sigma_{i,n}$ are the i^{th} uncertainty components corresponding to mast *m* and *n*, expressed as a percent of wind speed

w_m or w_n are the fraction of plant energy represented by each mast (energy weighting), expressed as a percentage

c_{mn} are the inter-mast correlation coefficients, expressed as dimensionless values between 0 and 1

In the case that uncertainty components $\sigma_{i,m}$ and $\sigma_{i,n}$ are fully correlated across masts ($c_{mn} = 1$ for all m,n) and Equation (8-3) reduces to simple addition across masts, $\sigma_i \to \sum_m \sigma_{i.m}$.

Analogous to Equation (8-1), for decorrelation between uncertainty components across masts, a reduced correlation coefficient (ρ_{jk}) results in a reduced total uncertainty.

Subsequently, the components can be combined according to (8-2) and (8-3). In practice most uncertainty components have $\rho_{ij} = 0$ but those from the list in Annex B may have nonzero cross-component correlations.

8.3 From wind speed to energy uncertainty; the energy sensitivity factor

The total uncertainty in mean wind speed $\sigma_{\text{tot},U}$ is related to the uncertainty in energy $\sigma_{\text{tot},E}$ by

$$\sigma_{\text{tot},E} = s_{UE} \sigma_{\text{tot},U} \qquad (8\text{-}4)$$

where

$\sigma_{\text{tot},E}$ is standard energy uncertainty, expressed as a percentage of net energy

s_{UE} is the speed-to-energy “sensitivity factor”, expressed as a ratio

$\sigma_{\text{tot},U}$ is wind speed uncertainty, expressed as a percentage of wind speed

The speed-to-energy (“sensitivity factor”) is defined by $s_{UE} \equiv \partial E / \partial U$. This can be approximated by a first order difference,

$$s_{UE} \equiv \frac{\partial E}{\partial U} \simeq \frac{\Delta E}{\Delta U} \tag{8-5}$$

Where:

s_{UE} is the speed-to-energy “sensitivity factor”, expressed as a ratio

$\frac{\partial E}{\partial U}$ is sensitivity coefficient, expressed in differential form

$\frac{\Delta E}{\Delta U}$ is sensitivity coefficient, expressed in discrete form

For a given energy calculation driven by wind speed statistics (including wake effects) one perturbs the mean wind speed (input) by $\pm\Delta U/2$ to calculate the corresponding ΔE. A value $\Delta U = 2\sigma_{\mathrm{tot},U}$ is specified; if another value is chosen for ΔU, this must be reported and explained.

In general, for a given wind farm the total energy may exhibit a non-linear dependence on mean wind speed, so that s_{UE} is also a function of wind speed. Thus s_{UE} may be checked using multiple ΔU; one can also calculate bin-wise $s_{UE}(U)$ if one has computed a ‘wind farm power curve,’ i.e., $E(U)$. It is assumed that the long-term s_{UE} is the same as that obtained from the limited measurements—that the *shape* of $E(U)$ does not change.

As an advanced option, one may additionally undertake the above per wind direction sector, and report sectoral frequency-weighted calculations, to obtain a total uncertainty.

Table 8-1 – Measurement-Based Uncertainties, Wind-related

Wind Related Uncertainty Components
Historical Wind Resource
Representativeness of Long-term Period
Reference Data Consistency
Reference Data-Measurements
Reference Data-Modelled
Long-term Adjustment (MCP/method)
(Wind Speed) Distribution Uncertainty
On-site Data Synthesis (gap filling)
Measured Data Representativeness
Project Evaluation Period Variability
Wind Speed Variability (IAV)
Climate Change
Plant Performance (availability, environmental)
Measurement Uncertainty
Wind Speed Measurement
Wind Direction Measurement / Rose
Other Atmospheric Parameters
Data Integrity and Documentation
Horizontal Extrapolation
Model Inputs
Model Sensitivity/Stress
Model Appropriateness
Vertical Extrapolation
VE model Uncertainty
Excess Propagated Measurement Uncertainty

Table 8-2 – Measurement-based Uncertainties, energy-related

Energy Related Uncertainty Components
Plant Performance
Turbine Interaction/Wake and Blockage Effects
Availability
Turbine
BOP
Grid
Electrical
Electrical Efficiency
Facility Parasitic Consumption
Turbine Performance
Sub-optimal Performance
Generic Power Curve Adjustment
Site-specific Power Curve Adjustment
High Wind Hysteresis
Environmental
Icing
Degradation
Environmental Loss (External conditions)
Exposure Changes
Curtailment / Operational Strategies
Load Curtailment
Grid Curtailment
Environmental / Permit Curtailment
Operational Strategies

9 Plant Performance Loss Calculation and Uncertainty

Losses in a wind farm are specified here as a percentage in relation to the gross energy yield. Uncertainty expressed as a percentage defined as standard deviation divided by average.

9.0 Net Energy Estimation

9.1 Loss Assessment

Plant performance losses calculation methods are not normative in this standard, but their categorization and table for reporting them is normative.

Table 3 – Overview of plant performance losses.

Loss category	Loss Sub-categories
Turbine Interaction	Internal Turbine Interaction Loss (inc. Wake and Blockage Effects)
	External Turbine Interaction Loss (inc. Wake and Blockage Effects)
	Future Turbine Interaction Loss (inc. Wake and Blockage Effects)
Availability	Turbine availability
	Balance of plant (BoP) availability
	Grid availability
Electrical	Electrical Efficiency
	Facility parasitic consumption
Turbine performance	Sub-optimal wind farm performance
	Generic Power Curve Adjustment
	Site Specific Power Curve Adjustment

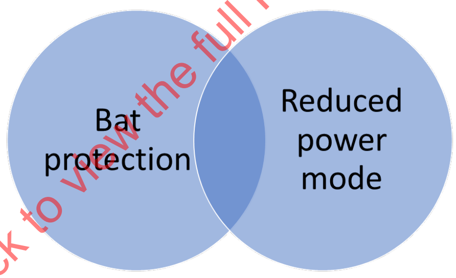
	High wind hysteresis
Environmental	Icing
	Degradation
	Environmental
	Exposure changes
Curtailments	Loads curtailment
	Grid curtailment
	Environmental/Permit curtailment
	Owner directed operational strategies

Losses shall be expressed as an efficiency factor, η_i, where η_i = 1 - $loss_i$. The Net Energy shall be calculated as the product of the Gross Energy and the individual loss factors, as shown in equation X. The origin, magnitude, and uncertainty of the individual loss factors shall be specified and be presented in a tabular form to match right column of Table 3.

$$\eta_{total} = \eta_1 * \eta_2 * \eta_3 * \ldots * \eta_i$$

$$AEP_{NET} = AEP_{GROSS} * \eta_{total}$$

Note: situations arise where losses cannot simply be multiplied. This occurs when individual losses affect one another. In this scenario, an effective efficiency factor may be calculated for the individual losses such that they may be treated as above. For example, losses due to bat protection (e.g. from sunset until sunrise) and reduced power modes during night times (e.g. from 22 h to 6 h) shall be calculated considering the temporal overlap when both modes are occurring simultaneously, as depicted graphically below.



9.2 Uncertainty Assessment

The categorical loss uncertainties are expressed as a percent of gross energy. All uncertainty values reported shall be calculated according to the normative methods detailed in the Uncertainty Model elsewhere in this standard, with the following exception. The preparer of the report may use an alternative uncertainty calculation for a subcategory provided that the method of calculation and assumptions made are described in the report, and that those methods and assumptions are supported with citable studies.

It is important to stress that the methodologies to calculate the loss uncertainties as per this standard have varying maturity: While a limited number of plant performance loss uncertainties can be derived directly from loss measurements (e.g. Generic Power Curve Uncertainty can be derived from the spread of measured power curve test results), most plant performance loss uncertainties revert to common practice and a benchmarking exercise that has been undertaken since no analytical common approach exists for determining them. The results of the benchmarking exercise are indicated in the following section by “The uncertainty range typically considered is between x % and y %”. The uncertainty calculation methodology in the uncertainty model reflects this benchmarking exercise.

Each of the following subsections is structured as follows:
First, there is a brief description of the plant loss category. The uncertainty range derived from benchmarking is provided, followed by a list of uncertainty drivers that “must be considered”. To calculate the uncertainty for each driver the user is referred to the driver category of the respective plant performance loss uncertainty in the uncertainty model. Where necessary, more detail to the uncertainty

quantification is provided, e.g. for the uncertainty driver “Completeness of BOP design and relevant components and subsystems“ of the Balance of Plant uncertainty the following detail is provided: where an indicative study is considered “preliminary” and a final study approved by an engineer of record is called “final” as per the uncertainty model.

9.2.0.0 Turbine (or Wind Farm-Atmosphere) Interaction

Turbine Interaction Loss is defined as the difference between the total power produced by the wind farm and the sum of the powers that would be produced by each turbine if each were operating in isolation. It represents a long-term average reduction in energy yield due to aerodynamic interactions between the turbines and the atmosphere. Array efficiency is defined as 100% minus this turbine interaction loss. Mathematically, this can be stated as:

$$TurbineInteractionLoss = 100\% - \overline{\eta_{array}}$$

$$\overline{\eta_{Array}} = \frac{Net\ Energy\ Yield}{Gross\ Energy\ Yield} = \frac{\int_0^{2\pi}\int_0^{Vmax}\sum_1^{nTurbines} P_{InArray}\, p(V,\theta)dVd\theta}{\int_0^{2\pi}\int_0^{Vmax}\sum_1^{nTurbines} P_{InIsolation}\, p(V,\theta)dVd\theta}$$

where:

- $p(V,\theta)$ is the probability density of wind speed V and direction θ (i.e. the wind rose), the integral of which is 1.
- $P_{InArray}$ is the power generated by the wind turbine when it is positioned inside the array
- $P_{InIsolation}$ is the power that the turbine would generate if it were operating in isolation

The aerodynamic interactions between wind turbines and wind turbines and the atmosphere are complex, and are the topic of much ongoing research. The future direction of the industry is not known, but this section aims to accommodate current common practice as well as continuing and expected advances in methods for energy yield assessment; the latter are usually evaluated using relatively simple wake models. Though there is substantial variation across the industry, these wake models include various assumptions and limitations; typically, one or more of the following are implicit in such models:

- Assume that each turbine only affects turbines downwind;
- Assume an initial, idealised velocity deficit downwind of the rotor, then model how this dissipates via turbulent mixing;
- Include empirical parameters, allowing them to be tuned to measured production data;
- Assume steady-state conditions or calculate only temporally-averaged effects;
- Incorporate some sensitivity to certain characteristics of the inflow conditions (e.g. turbulence intensity) but disregard other characteristics (e.g. the capping inversion);
- Use superposition to combine individual turbine wakes into a wind farm flow field;
- In some cases, fail to respect conservation of mass and/or momentum; and,
- In some cases, require additional terms to capture wake losses inside large wind farms.

By contrast, turbine interaction losses are known to:

- Include upwind and lateral interactions caused by the pressure fields induced by the turbines, which in turn affect the wake development;
- Be sensitive to a complex and interconnected set of inflow characteristics (e.g. stability, shear and veer, turbulence characteristics, boundary layer height);
- Be strongly influenced by dynamic, unsteady turbulent process driven by ever-changing inflow conditions as well as internally-generated unsteadiness;
- Interact with terrain topography and roughness, and be influenced by hub height; and,
- Be driven by physical processes which obey conservation laws (mass, momentum, energy etc).

Ideally, all of these interaction effects would be captured in a single integrated model, so that all of the feedback effects are included. However, such models may be too computationally expensive to apply for all use cases, particularly when iterating on many potential turbine array scenarios. It is expected that the industry will move towards routine use of integrated models as these models develop, computing power grows and more comprehensive validation datasets become available. However, at present, it is rather common to separate out turbine interaction effects into multiple categories:

- Wake effects, which include (at least) the turbulent diffusion of the velocity deficit behind each rotor; and,
- Blockage effects, which include (at least) the slow-down of the wind upstream of a set of wind turbines due to the pressure gradients generated by those turbines' thrust.
- Other wind farm or turbine atmosphere interaction effects

When segregating the modelling approach in this way, care must be taken to ensure that no effects are double-accounted or omitted, and that all relevant feedback/coupling effects are included. In particular, inviscid effects inside the wind farm must be considered carefully. This is discussed further in Section X.

Three categories of turbine or wind farm-atmosphere interaction losses must be considered:

1. Internal turbine interaction losses, i.e. the energy change occurring due to wake, blockage, and other interactions between turbines and the atmosphere in the same wind farm;
2. External turbine interaction losses, i.e. the loss occurring due to the impact of wake, blockage, and other interactions between the subject wind farm and those generated by existing turbines external to the wind farm; and,
3. Future turbine interaction losses, i.e. the loss occurring due to the impact of wake, blockage, and other interactions between the subject wind farm and those generated by wind farms which are likely to be built in the future. If required for the analysis, additional possible scenarios of possible future speculative external wind farms may be analysed, with an appropriate description of the scenarios considered and the rationale for their consideration.

Each of these three categories can be predicted by using either

- Separate models for wake and blockage, using the approaches described in Section X or,
- A single integrated model encompassing all of the key physical drivers, using the approach described in Section X.

For the calculation of external or future turbine interaction losses, all wind turbines that could have a cumulative non-negligible impact on the target wind farm shall be considered. Non-negligible wake effects have been shown to persist for several hundred turbine rotor diameters (or several wind farm mean diameters) under stable atmospheric conditions offshore. For consistency, the same set of neighbouring wind farms should be considered for both wakes and blockage, or other effects, if separate models are being utilized. A consistent approach to uncertainty assessment is applied across all segregated and integrated modelling approaches, as explained in Section X.

Segregated Wake and Blockage Modelling

If and when segregating wake and blockage effects into separate models, there are six loss sub-categories which must be considered, as summarised in Table 1.

Table 1 – Segregated Modelling Approaches

Category	Sub-Category	Segregated Modelling Approach
Internal Turbine Interaction Loss	Internal Wake Loss	Wake model of the wind farm in question
	Internal Blockage Effect	Blockage model of the wind farm in question, if calculated separately
External Turbine Interaction Loss	External Wake Loss	Wake model of the wind farm in question and its existing neighbours. Factor out the internal wake loss to isolate the external wake loss.
	External Blockage Effect	Blockage model of the wind farm in question and its existing neighbours. Factor out the internal blockage effects to isolate the external blockage effect, if calculated separately

Future Turbine Interaction Loss	Future Wake Loss	Wake model of the wind farm in question, its existing neighbours and its potential future neighbours. Factor out the internal and external wake losses to isolate the future wake loss.
	Future Blockage Effect	Blockage model of the wind farm in question, its existing neighbours and its potential future neighbours. Factor out the internal and external blockage effects to isolate the future blockage effect, if calculated separately

The analyst must clearly specify:

- The scope of the wake model, i.e. the physics which the model is formulated to capture ("intended scope") and the physics it may capture inadvertently through tuning to measured datasets ("emergent scope").
- The scope of the blockage model, i.e. the physics which the model is formulated to capture ("intended scope") and the physics it may capture inadvertently through tuning to measured datasets ("emergent scope").
- The means of coupling and/or combining the wake and blockage models to obtain an overall turbine interaction loss.

This distinction between intended and emergent scopes is crucial. For example, consider a wake model incorporating only a velocity deficit behind each rotor and an empirically-tuned dissipation rate. If that dissipation rate is tuned to measured production data, using the leading row as a reference, it will inevitably capture some of the inviscid effects inside the wind farm. These are not part of the model's formulation but will be present in its output, so including these internal inviscid effects within a blockage model would result in the double-accounting of that effect.

Generally, a mismatch between the intended and emergent scopes of a model may reduce its ability to work consistently across a range of wind farm sizes and geometries.

The analyst must demonstrate that the combination of wake and blockage models neither double-accounts for any effect nor misses out any effects that have a significant impact on energy yield. In general, there are (at least) two ways in which this can be achieved:

- Segregating by location, i.e. upstream vs within the wind farm.
- Segregating by physics, i.e. viscous vs inviscid effects.

Both approaches are considered to be valid and for details of both approaches please refer to Appendix A. Means of demonstrating that these requirements have been met are summarised in the reporting section.

Wakes

Wind turbines extract energy from the wind and induce turbulence and wind speed deficits downstream. This downstream effect is known as a wind turbine wake. As the flow proceeds downstream, the wake spreads and recovers towards freestream conditions. The wake effect is the aggregated influence of these wakes on the energy production of the wind farm.

These effects are known to be sensitive to various characteristics of the atmosphere, including the freestream turbulence intensity, shear, and atmospheric stability. Different models capture these effects in different ways. Depending on site specific wind farm, meteorological and physiographic conditions, material instantaneous or persistent velocity deficits associated with wind farm wakes may linger for long distances, from several rotor diameters to a few hundred rotor diameters, downstream.

The uncertainty assigned to wake losses can be expressed as a fraction of the absolute wake loss. The typical uncertainty range is between around 10% and 60% of the wake loss; the specific value must be evaluated based on validation data as described in Section .

When reporting the wake loss, the analyst must record:

- The software (including version number) used for the calculation;
- The wake model employed, the wake superposition method used (if any) and the values of any user-specified parameters;

- The physical basis for the model, whether or not the model conserves mass, momentum and energy, any significant numerical approximations (e.g. parabolic rather than elliptic solution), whether any deep array correction is used, and the process by which any empirical parameters have been tuned;
- Any differences in setup between the calculation in question and the validation cases;
- The atmospheric variables to which the wake model is sensitive (e.g. freestream turbulence, atmospheric stability etc.), the ways in which these variables influence the results, the values used in the analysis and the origins of those values;
- The verification checks that have been performed on the analysis; and,
- The wake losses for each individual WTG and for the entire wind farm for the Internal, External and Future categories.

Blockage Effects

As the wind approaches the rotor of a wind turbine, its speed reduces and the pressure increases in response to the turbine thrust. For an individual turbine, this behaviour is well-understood: the induction zone (the region over which this slow-down occurs) has been studied extensively[2]. However, with a large wind farm, there is a complex two-way interaction between the wind farm and the atmosphere, where flow is diverted over and around the leading turbines due to the aggregate effect of multiple induction zones from the field of wind turbines. This effect is referred to as blockage.

The most striking effect of this is that the leading-row turbines may not experience the same wind speed as they would without the influence of the rest of the wind farm. This violates an assumption made in wakes-only models, namely, that the aerodynamic impact of wind turbines only extends downwind. This means that when turbine interaction models are validated using the leading-row powers as a reference, they exclude this change between freestream and leading-row conditions. The same inviscid effects can cause a recovery in the wind speed further downwind and/or around the wind farm which a wakes-only model would not capture unless it was tuned to fit such data.

Blockage effects are sensitive to various characteristics of the atmosphere that change in time and space, such as wind direction, and most significantly, with the degree of thermal stratification, both within and above the boundary layer. With stable stratification, any obstacle may generate gravity waves which propagate away from the disturbance. Relevant parameters are thought to include boundary layer depth, strength of the capping inversion and the lapse rate in the free atmosphere (static stability). Even though thermal stability has an influence on blockage effects, many blockage models at present use gross approximations to represent this influence or ignore it altogether. With a wide variety of approaches in use and little consensus on what approaches are acceptable, validation will be the key to separating reliable approaches from those that are not.

To predict wind farm energy yield accurately, what matters is that the blockage model and wake model, or a combined approach that encompasses both effects, work together to account for all physical processes with a non-negligible impact on energy yield in a consistent manner. In practice this will often mean that the blockage and wake models must be validated together against measurements of the combined effects.

The uncertainty assigned to blockage is usually expressed as a proportion of the absolute blockage effect. The typical uncertainty range is between around 10% and 60% of the estimated blockage effect; the specific value must be evaluated based on validation data as described in Section _. At present there is a dearth of measured data available for validation, though such datasets are beginning to emerge.

When reporting the blockage loss, if separable in the method utilized, the analyst must record:

- The software (including version number) used for the calculation;
- The blockage model employed and the values of any user-specified parameters;
- The physical basis for the blockage model, the superposition method used (if any) and the process by which any empirical parameters have been tuned;

2 See, e.g., F.E.Brink, N.G.Nygaard, *Measurements of the Wind Turbine Induction Zone*, 21st Meeting of the Power Curve Working Group, Glasgow, 13 Dec 2016

- A clear rationale that the wake and blockage models are complementary, i.e. all physical effects are accounted for and none are double-accounted;
- Any differences in setup between the calculation in question and the validation cases;
- The atmospheric variables to which the blockage model is sensitive (e.g. atmospheric stability, boundary layer height etc.), how these variables influence the results, the values used in the analysis and the origins of those values;
- The verification checks that have been performed on the analysis; and,
- The blockage effects for each individual WTG (if available) and for the entire wind farm for the Internal, External and Future categories.

Integrated Turbine Interaction or Wind Farm-Atmosphere Interaction Modelling

When calculating wake and blockage effects together in an integrated model, there are three loss categories which must be considered, as summarised in Table 2. Each of these has a corresponding uncertainty value. There is no requirement to split the result into wake and blockage components.

For a wind farm that is part of a large cluster, it may be practical to run an integrated model (such as RANS CFD) for the wind farm in isolation but not for the whole cluster. In this case, it is acceptable to mix the integrated and segregated modelling approaches, as long as the combined approach has a rigorous technical justification.

Table 2 – Integrated Modelling Approaches

Category	Integrated Modelling Approach
Internal Turbine Interaction Loss	Single integrated model of the wind farm in question
External Turbine Interaction Loss	Single integrated model of the wind farm in question and its existing neighbours. Factor out the internal turbine interaction loss to isolate the external turbine interaction loss.
Future Turbine Interaction Loss	Single integrated model of the wind farm in question, its existing neighbours and its planned or potential future neighbours. Factor out the internal and external turbine interaction losses to isolate the future turbine interaction loss.

The uncertainty assigned to the turbine interaction loss is usually expressed as a proportion of the absolute turbine interaction loss and is calculated as described in Section . When reporting the turbine interaction loss, the analyst must record:

- The software (including version number) used for the calculation;
- The model employed and the values of any user-specified parameters;
- The physical basis of the turbine interaction loss model, any superposition methods used, and the process by which any empirical parameters have been tuned;
- Any differences in setup between the calculation in question and the validation cases;
- The atmospheric variables to which the turbine interaction loss model is sensitive (e.g. stability, boundary layer height etc.), the methods by which those sensitivities are accounted for, the values used in the analysis and the origins of those values;
- The verification checks that have been performed on the analysis; and,
- The losses for each individual WTG and for the entire wind farm for the Internal, External and Future categories.

It is acceptable to report different values of future turbine interaction losses for different scenarios of built-out of neighbouring projects. Each scenario would have to be modelled separately.

Reporting requirements specific to wake models, blockage models and integrated turbine interaction loss models are covered in Sections , and respectively.

The pattern of production (i.e. power from each turbine) should be reported for a set of representative wind speeds and directions.

Uncertainty Evaluation

To evaluate the uncertainty of the integrated or separated wake and/or blockage modelling, the following points shall be noted.

- In general, wind farms which have been used to tune empirical parameters in wake, blockage or integrated models cannot then be used for validation studies. Validation should be a separate step from tuning.
- Validation studies should consider the same combination of wake and blockage model as is being applied.
- The way in which wake losses are quantified in the measured data (e.g. with reference to the freestream wind speed or to the front-row powers) must be consistent with the way the wake model is used.
- The validation studies cited must be relevant to the application; for example, when using a wake, blockage or integrated model for long-range interactions between wind farms as part of an External or Future Loss calculation, the validation studies must address wake, blockage or turbine interaction losses over comparable distances
- Measuring blockage effects is difficult. The effect is fairly subtle, and there are competing uncertainties in establishing the true freestream conditions: measurements too close to the wind farm will be subject to the blockage effect; measurements too far away will be decorrelated from the conditions at the wind farm. The uncertainty in the measurements should be considered when assessing the results of any validation study.
- Most wake model validations are based on measured production data using the leading row as reference. As explained earlier these validations will inevitably capture some blockage effects. However, blockage effects are small compared to wake effects. Therefore, unless demonstrated otherwise, the uncertainty of both the wake and blockage models should be derived from the spread of these validation results as per the uncertainty evaluation process described in this section below.
- Alternatively, separating the uncertainty assessment into non-waked and potentially-waked components may be more consistent with the validation data available. Please refer to the recommendations in Appendix A.
- If an ensemble of models is used, validation studies should be performed on the ensemble results rather than just on the individual models within the ensemble, so that a suitable uncertainty estimate can be established for the ensemble.
- For CFD-based models, the validation studies must state the minimum and typical element sizes, the domain extent, type of boundary conditions, and any other critical parameters, to ensure that a similar mesh is used for the present analysis. Ideally this should be reported in the form of a best practice guideline for the model.

<u>Uncertainty evaluation process:</u>

To evaluate the uncertainty of the turbine interaction loss, wind farm-atmosphere interaction, or wake and blockage losses, the following must be considered:

- Magnitude of loss predicted, since the uncertainty will be provided as a percentage of that loss, i.e. a 20% loss uncertainty with respect to a 10% wake loss would yield a 2% wake loss uncertainty with respect to AEP.
- Validation process whereby the uncertainty of a given applied wake model, is calculated based on the number of validation cases it went through on a subset of possible scenarios/conditions (i.e. turbine array configuration, turbine dimensions, terrain complexity, atmospheric conditions), and an application process that adjusts and extends the uncertainty in case a different set of scenarios/conditions are studied.

The uncertainty evaluation process has two steps as per the Uncertainty Model:

1. Validation of the model: This step will determine the associated wake model uncertainty.

2. Application of the model: This step will determine whether differences between application and validation cases require to increase the wake model uncertainty.

Unless it can be demonstrated otherwise, individual validations shall be grouped into projects with 3 rows or less, and 4 rows or more.

Validation of the model:

Depending on the number of validation cases, the associated model uncertainty will differ as depicted in the below Table. With more than 5 cases, the uncertainty shall be derived from the spread of validation results.

Application of the wake model:

	Application case					
		Neutral on shore	Offshore	Stable/Unstable onshore	Complex terrain	Mountain Pass
Validation case	Neutral Onshore	0	10%	15%	20%	35%
	Offshore	10%	0	10%	15%	35%
	Stable/Unstable Onshore	10%	10%	0	10%	35%
	Complex terrain	10%	20%	20%	0	25%
	Mountain pass	10%	10%	10%	10%	0

Both the application case and the validation cases should be classified by the following classification scheme which is motivated by empirically observed wake model performance variations with terrain complexity, wind flow regime and atmospheric conditions (e.g. due to significant diurnal variation in stability). The classification scheme has the following five categories:

- **Offshore:** A wind farm project with turbine foundations permanently under sea level or in the inter-tidal zone or in large water bodies is classified as an Offshore project.
- **Stable/Unstable Onshore** sites are defined as sites that show both more than 30% of strong stability (alpha>0.3) and more than 30% of unstable stratification (alpha<0.1). Sites that don't fall in this category are classified as **Neutral Onshore**. It is recommended to calculate the wind shear (or power law) exponent alpha from wind speed measurements that span at least one year at minimum two heights separated by more than 20 meters, where the top height minimum is 2/3 of hub height.
- **Complex terrain:** A wind farm project that is assessed as complex and assigned the complexity category H as described in IEC 61400-1 Ed 4 Section 11.2.
- **Mountain pass**: A wind farm situated within or next to a mountain pass.

Coastal onshore cases may also be considered as a separate category..

Examples for wake model uncertainty calculation:

- Example 1: The wake model was validated for 4 Neutral Onshore wind farms with 3 rows or less, the associated uncertainty of the wake model is 20%. The wake model is applied for a wind farm with 3 rows or less that is classified as Neutral Onshore. Since the wake model is validated and applied for Neutral Onshore wind farms there is no additional uncertainty as per the above table. Thus the resulting wake model uncertainty is 20% of the wake loss.
- Example 2: Wake model validation as per Example 1 (20% associated wake model uncertainty). The wake is applied for a Complex terrain wind farm, an additional uncertainty of 20% needs to be added as per the above table. The resulting wake model uncertainty is 20%+20%=40% of the wake loss.
- Example 3: Wake model validation as per Example 1. The wake model is applied for a big wind farm with 4 rows or more. Since there are no wake model validation cases for a projects with 4 rows or more, the associated wake model uncertainty is 60% which is also the maximum wake model uncertainty.

- Example 4: The wake model was validated for 6 Neutral Onshore wind farms with 3 rows or less, the wake model uncertainty is derived from the spread of validation results. If the wake model is applied for a Neutral Onshore wind farm with 3 rows or less no additional uncertainty needs to be added as per the above table. If the wake model is applied for e.g. a Stable/Unstable Onshore project 15% of uncertainty needs to be added to the uncertainty derived from the validation results.

9.2.0.1 Availability

Availability losses result from the inability to deliver power in conditions defined in the WTGS specifications excluding losses accounted for elsewhere. The primary drivers behind availability losses are scheduled maintenance and unscheduled maintenance (driven by component failure rates and operator response time).

In a preconstruction assessment, a production-based availability shall be used, as defined in the IEC 61400-26-2. A number of downtime categories are, however, treated separately in a preconstruction assessment so the definition needs to be modified for this purpose. Explicitly, the following items should not be included in the availability downtime calculation:

- Partial Performance (IAOGPP) – should be treated as turbine performance or curtailment
- Out of Environmental Specification (IAONGEN) – should be treated as environmental loss
- Requested Shutdown (IAONGRS) – should be treated as curtailment or environmental

WTGS(s), Balance of plant and Grid will not be available the total time of an operating year. In the following all the items to be considered to properly take into account availability-related energy losses and relevant uncertainties.
Availability losses occur when WPS and/or WTGS(s) are not performing its intended services within the design specification.
Note: appropriate warranty provision under WTGS(s) and Balance of plant O&M contracts other than Grid connection agreements signed with TSO can mitigate the financial risk associated with availability losses but will not generally affect production.

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9.2.0.1.1 Turbine Availability

Turbine Availability is intended to account for the portion of potential production lost due to the turbine, or turbines, not being able to produce power.

Turbine availability considered here is the technical turbine availability defined in 61400-26-2, equation B.5. In the context of the 61400-26-2, the portion of the overall availability which is associated with the WTGS excludes the following items:

- Partial Performance (IAOGPP) – should be treated as turbine performance or curtailment
- Out of Environmental Specification (IAONGEN) – should be treated as environmental loss
- Requested Shutdown (IAONGRS) – should be treated as curtailment or environmental:
- Out of Electrical Specification (IAONGEL) – should be treated as grid or BoP availability, depending on the cause.
- Forced Outage (IAONOFO) – if associated with balance of plant, shall be treated as BoP Availability.

The Turbine Availability over the operational period shall consider the impact of lower availability during start-up and late-life.
The uncertainty range typically considered is between 2.0% and 5.0%.

To evaluate the uncertainty of WTGS availability the following must be considered:

- Strength of the warranty provided by O&M contract for the WTGS signed or to be signed with the O&M service provider. This is related also to the:
    - services included in the scheduled and preventative maintenance provided
    - carve-outs included by the O&M service provider in the availability calculation formula/procedure
    - financial guarantees and penalties, as they are expected to influence actual production

where a warranty is considered “strong” as per the uncertainty model if an availability warranty with carve-outs with an insignificant effect on availability (where insignificant means less than 0.25% of AEP loss) has been signed and “poor” if there is no availability warranty.

- Track record of O&M service provider as measured by number of turbines under O&M contract in similar conditions and technology, considering:
  - the WTGS technology
  - the available documentation provided by the O&M service provider with respect to the availability figures obtained over the years on the serviced WPS(s) / WTGS(s)
- Reliability and track record of the technology used in the WTGS(s) as measured by the number of turbines of the WTGS model with similar technology installed
- Maturity of market and infrastructure as measured by the installed capacity, where a total installed capacity of less than 500 MW is an “emerging” market, less than 4 GW is an “developing” market and more than 4 GW are a “developed” market as per the uncertainty model.

9.2.0.1.2 Balance of plant availability

The BOP availability is the fraction of a given operating period in which a BOP is performing its intended services within the design specification.

The factor covers the BOP availability related to potential energy production over the operational period, considering:

- BoP design, including circuit length, circuit technology, joints/weak points, transformers, switch gear, reactors, filters, etc. and degree of redundancy
- warranted availability as it is seen to impact power produced
- O&M strategy

In the context of 61400-26, BOP availabilty is defined as:

- Out of Electrical Specification (IAONGEL) – should be treated as grid or BoP availability, depending on the cause.
- Forced Outage (IAONOFO) – if associated with balance of plant, shall be treated as BoP Availability.

The BoP Availability over the operational period shall consider the impact of lower availability during start-up and late-life.

The uncertainty range typically considered is between 0.5% and 2%.

To evaluate the uncertainty of BoP availability the following must be considered:

- Completeness of BOP design and relevant components and subsystems, where an indicative study is considered “preliminary” and a final study approved by an engineer of record is called “final” as per the uncertainty model.
- Strength of the warranty provided by O&M contract for the BOP with the O&M service provider. This is related also to the:
  - Status of the O&M contract,
  - services included in the scheduled and preventative maintenance provided
  - carve-outs included by the O&M service provider in the availability calculation formula/procedure
  - obligation and limitation of responsibilities of the O&M service provider
  - financial guarantees and penalties, as they are expected to influence actual production

  where a warranty is considered “strong” as per the uncertainty model if a BOP warranty with carve-outs with an insignificant effect on BOP availability (where insignificant means less than 0.25% of AEP loss) has been signed and “poor” if there is no BOP warranty
- Track record of O&M service provider as measured by the number of similar assets considering:
  - the country/region/area
  - the available documentation provided by the O&M service provider with respect to the availability figures obtained over the years on the serviced WPS(s)
  - Asset technology
- Maturity of market and infrastructure, where a total installed capacity of less than 500 MW is considered an “emerging” market, less than 4 GW an “developing” market and more than 4 GW a “developed” market as per the uncertainty model.

9.2.0.1.3 Grid Availability

The Grid availability is the fraction of a given operating period in which a grid is performing its intended services within the design specification.

To be underlined that this factor is related to the grid being outside the operational parameters defined in the Grid connection agreement signed with TSO as well as actual grid downtime.The factor covers the Grid availability related to potential energy production over the operational period, considering:

- Grid outage track record
- restart after grid outage. This represents the stand-by period while the WTGS components are brought within their operating specifications.

The uncertainty range typically considered is between 0.2% and 1.0%.
To evaluate the uncertainty of Grid availability the following must be considered:

a) Completeness of a site specific grid reliability study. A regional grid study would be considered “preliminary” in the uncertainty model, while the site specific grid reliability study would be considered “final”.

9.2.0.2 Electrical Efficiency

9.2.0.2.1 Electrical Efficiency

Electrical losses represent the difference between the energy production predicted at the wind turbine and the metering point.

To properly calculate the electrical efficiency, it is important to know where the power curve is defined (e.g. on the low or medium voltage side of the turbine transformer) and where the energy will be metered, noting that the meters are not always physically located at the metering point (in which case an adjustment will be necessary).

The uncertainty range typically considered is between 0.25% and 1.0%.
To evaluate the uncertainty of electrical efficiency the following must be considered:

- Completeness of collection system design, where an indicative study is considered “preliminary” and a final study approved by an engineer of record is called “final” as per the uncertainty model.

9.2.0.2.2 Facility parasitic consumption

Energy consumed by plant and turbine parasitic electrical losses, while operating or not operating, and through the operation of turbine extreme weather packages, where there could be an impact at the energy measurement point.

The uncertainty is typically less than 0.25%.
To evaluate the uncertainty of facility parasitic consumption the following must be considered:

- Completeness of available information on extreme weather packages and other site electrical loads.

9.2.0.3 Turbine performance

Turbine performance loss is the deviation of the actual power output from the modelled output resulting from a variety of operational characteristics. This can include losses due to the turbine not producing to its reference power curve within test specifications, losses due to differences between turbine power curve test conditions and actual conditions at the site (e.g. turbulence, inclined flow, off-yaw axis winds, wind shear, wind veer), operational issues (e.g. yaw misalignment, WT instrumentation errors, blade pitch inaccuracies) and high wind hysteresis losses.

9.2.0.3.1 Sub-optimal wind farm performance

This loss accounts for performance deviations from the optimal wind plant performance due to software, instrumentation, and control setting issues (e.g., yaw misalignment, WT instrumentation errors, blade pitch inaccuracies) which cause the machines to not reach their intended power curve or operate in a non-optimal way.
The uncertainty range typically considered is between 0.5% and 1.25%.
To evaluate the uncertainty of sub-optimal wind farm performance the following must be considered:

- Track record of the O&M provider and quality of the ongoing O&M strategy,

- Quality of commissioning. By way of example considering the completeness of the commissioning documentation and any third-party assessment made on the commissioning activities. An inexperienced commissioner with less than 10 commissioned turbines would be considered “low” quality in the uncertainty model, “high” quality commissioning can be identified by the provision of a commissioning checklist with all the required checks and tests and the plan for or completion of an independent verification of the commissioning.

9.2.0.3.2 Generic Power Curve Adjustment

This loss represents the expected deviation between the power curve considered and the power curve which would be measured under standard test conditions.

The uncertainty range typically considered is between 1% and 3%.

To evaluate the uncertainty of generic power curve adjustment the following must be considered:

- Number of measured power curve test (conducted according to 61400-12) (either raw PPT data or PPT results)

In the scenario when 0-1 test are available, the uncertainty shall be 3%; with 2-5 tests, the uncertainty shall be 2%; with more than 5 tests, the uncertainty shall be derived from the spread of test results.

9.2.0.3.3 Site Specific Power Curve Adjustment

This loss represents the deviation in turbine performance where atmospheric conditions (eg turbulence, wind shear, veer or up-flow angle) are considered to be materially different at the wind farm site than that which is experienced under standard test conditions.

The uncertainty range typically considered is between 0.3% and 2.0%.
To evaluate the uncertainty of site-specific power curve adjustment the following must be considered:

- Amount of time operating in outer range,
- Accuracy of model to predict performance in outer range,
- track record in similar site/climatic conditions.
  - Air density, turbulence, shear, veer, inflow angle.
- Representativeness of power curve/controls (e.g. if your power curve is for the appropriate air density): A standard power curve document would be considered “standard info” in the uncertainty model, the provision of a site-specific power curve for site air density, turbulence and shear would be considered “good info”.

9.2.0.3.4 High wind hysteresis

This energy loss represents the energy lost between high wind speed cut-out and recut-in.

The uncertainty range typically considered is between 0.1% and 0.4%.
To evaluate the uncertainty of high wind hysteresis the following must be considered:

- Details of the control strategy: cut-out and re-cut in wind speeds at 10min would be considered “standard info” in the uncertainty model, higher resolution information of the control strategy, e.g. cut-out and re-cut in wind speeds at 10min, 5min and 3sec level or similar would be considered “good info”.
- availability of appropriate input data for modeling the control strategy over the life of the project: WRA wind data with an averaging interval of 10 minutes including standard deviation of wind speed and gust/max wind speed would be considered “standard” quality of input data in the uncertainty model. If beyond that everything needed for hysteresis calculation is provided, e.g. gust wind speed with a temporal resolution as required by the hysteresis model the quality of the input data can be set to “good” in the uncertainty model.

9.2.0.4 Environmental losses

9.2.0.4.1 Icing

The estimation of icing losses should be performed specifically for the site. Different methods can be applied for its determination, depending on the site and project specifications.

Icing losses represent any performance degradation due to ice build-up including shut down losses. The ice build-up and in turn the degradation depends on e.g. the kind of icing, the blade design, the degradation state of the blade, the turbine operation set point and the effectiveness of anti-ice and de-icing features and controls. Wind turbines are sometimes actively shut down due to icing build-up either to mitigate health and safety concerns in an attempt to prevent ice throw or to protect turbine components from excessive loading. Both are typically done by running specific controller strategies that are based on ice build-up detection (e.g. increase in blade mass, turbine or blade vibration changes or other ice detection equipment).

A site ice assessment is needed and thus icing uncertainties need to be quantified only for sites with high icing risks (e.g. all of Scandinavia or Canada) or if any of the following is true:

1. Hub height temperature is below 0°C concurrently with relative humidity of ≥96 % for ≥ 1 % of long-term annual average duration [% of time] or

2. Cloud base height at rotor icing height {HH + 1/3D, see (IEA Wind Task 19, 2017)} with simultaneous temperature < 0°C result to ≥ 0.5 % of long-term annual average duration [% of time] or

3. Validated regional or global icing map[3] indicates to ≥ 0.5 % of long-term annual average meteorological icing duration or 1 % of instrumental icing duration [% of time]

4. Site assessment results to long-term icing losses ≥0.5 % of AEP {larger than IEA Ice Class 1, see (IEA Wind Task 19, 2017)}

The uncertainty range typically considered is between 0.1% and 6.0%.

To evaluate the uncertainty of the icing loss, the following icing loss drivers must be considered:

A. Quality and accuracy of method (e.g. measurements, weather modelling) chosen to estimate site icing conditions
   - “High” uncertainty is 150% of absolute icing loss value: meteorological icing duration at rotor icing height [% of time] calculated as percentage of time per year the temperature at hub height is below 0°C concurrently relative humidity is above 96 %. The temperature and relative humidity time series source is either site measurements, a weather model or reanalysis dataset. Relative humidity measurements may ideally be selected from a nearby met station at a similar altitude close to ground level.
   - “Moderate” uncertainty is 50 % of absolute icing loss value: Calculate long-term average meteorological or instrumental icing duration at rotor icing height [% of time] (IEA Wind Task 19, 2017), (IEA Wind Task 19, 2016) using
     i. CBH (Cloud base height [m agl]) + T (Temperature [°C]) data from nearby met station or similar or
     ii. validated weather model analysis (e.g. WRF) using icing theory from ISO 12494 (Davis, et al., 2014), (Hämäläinen & Niemelä, 2017) or
     iii. using a validated regional or country specific icing map.
   - “Low” uncertainty is 20 % of absolute icing loss value following best practice from IEA Wind Task 19: one full winter measured meteorological or instrumental icing duration [% of time] at hub height or higher on-site. For meteorological icing
     i. a dedicated icing sensor may be used or
     ii. at temperatures below 0°C, a visibility sensor or webcam-based image analysis can be used to quantify the duration of low visibility where meteorological icing starts at values below 300 meter horizontal visibility (Ilinca, 2011) or
     iii. Webcam images can be also used to monitor stationary structures for calculating the duration [% of time] when ice mass build-up occurs.
   - For instrumental icing, a pair of fully heated sonic anemometer and unheated cup anemometer is recommended. The instrumental ice detection criteria needs to be reported. In absence of more advanced ice detection methods, a simple constant of 10-20 % may be used for wind speed degradation from the unheated cup anemometer compared to the heated reference

[3] For example, consider the global icing atlas or «WIceAtlas»: http://virtual.vtt.fi/virtual/wiceatla/

anemometer. Vertical extrapolation of icing duration to hub height is needed if measurements are 10 % below intended hub height. (IEA Wind Task 19, 2017)

B. Method and length of data used to estimate long-term (a minimum of 10-years), expected site icing conditions
   - "High" uncertainty is ±3% of AEP if icing loss < 3.0 %. If icing loss ≥ ±3.0 %, then 150 % of absolute icing loss value: short-term icing measurements or assessment less or equal to one year and no long-term adjustment.
   - "Moderate" uncertainty is ±2 % of AEP if icing loss < 3 %. If icing loss ≥ ±3 %, then 50 % of absolute icing loss value: No long-term adjustment but minimum 2 years using
     i. on-site icing measurements or
     ii. validated weather model analysis (e.g. WRF) + ISO 12494 (Davis, et al., 2014) (Hämäläinen & Niemelä, 2017), meteorological or instrumental icing duration [% of time] (IEA Wind Task 19, 2017) or
     iii. using a validated regional or country specific icing map for assessing long-term average meteorological or instrumental icing frequency at hub height or higher [% of time] (IEA Wind Task 19, 2017), (IEA Wind Task 19, 2016).
   - "Low" uncertainty is 20 % of absolute icing loss value using
     i. Minimum five years of on-site icing measurements or
     ii. a long-term adjustment using correlation analysis. Correlation between assessed short-term (e.g. 1 year) meteorological or instrumental icing duration and long-term reference values is to be assessed (month-to-month correlation minimum resolution).
   - Reference long-term meteorological or instrumental icing durations can be from
     i. weather model analysis (e.g. WRF) + ISO 12494 (Davis, et al., 2014) (Hämäläinen & Niemelä, 2017), meteorological or instrumental icing duration [% of time] or
     ii. CBH (Cloud base height [m agl]) + T (Temperature [°C]) data from nearby met station or similar -> meteorological or instrumental icing duration at hub height or higher [% of time] (IEA Wind Task 19, 2017), (Bernstein, et al., 2009).
   - Uncertainty is similar to wind speed IAV calculation method: IAV/sqrt(LT data length) where IAV is the inter-annual variability of the annual icing losses.

C. Knowledge of the turbine technology and site control strategy for iced turbines (e.g. systems to mitigate ice, shut down due iced blades as quickly as possible or normal operation until safety limits are reached)
   - "High" uncertainty is 50 % of absolute icing loss value
     i. no ice protection system (IPS) and not considered or no knowledge or
     ii. turbine equipped with IPS having a low track record (less than 50 turbine years) in similar site.
   - "Moderate" uncertainty is 30 % of absolute icing loss value
     i. no IPS and preliminary specifications showing that turbine controller has been designed according to IEC61400-1 Ed4 Icing Design Load Cases or similar or
     ii. turbine equipped with IPS having some track record (more than 50 turbine years) in similar site.
   - "Low" uncertainty is 10 % of absolute icing loss value
     i. no IPS and full knowledge about iced turbine control strategy including supportive SCADA measurements for similar site or
     ii. turbine equipped with IPS having good track record (more than 100 turbine years) in similar site.

Examples for icing loss uncertainty calculation:

- Example 1: The global icing atlas or "WIceAtlas", that has been validated with turbine SCADA from multiple sites in multiple countries, is used to estimate initial site-specific icing conditions for a wind farm resulting to an IEA Ice Class 2 being medium uncertainty for icing loss driver A at 50 % of the absolute icing loss value. Icing loss driver B is moderate at 50 % of the icing loss value as the WiceAtlas is long-term adjusted with more that 10-years of data. Icing loss driver C is moderate at 30 % of the absolute icing loss value as the site turbine has been designed according to cold climate design load cases using IEC 61400-1 ed4 standard. Thus, the final uncertainty is sqrt (0.5^2 + 0.5^2 + 0.3^2) = 77 % of the absolute icing loss value. The upper range value of the IEA Ice Class 2 icing loss estimate of 5.0 % can be used to estimate the absolute icing loss value. Thus the icing losses in this case are 5.0 ± 3.9 %.
- Example 2: 1-year onsite met mast measurements of instrumental or meteorological icing duration following the IEA Wind Task 19 best practices results to a low uncertainty for icing loss driver A at 20 % of the absolute icing loss value. Short 1-year measurements are long-term corrected with a MCP method using a weather model following ISO 12494 method for icing loss driver B being 20 % of the

absolute icing loss value. Icing loss driver C is low at 10 % of the absolute icing loss value as the icing control strategy of the turbine has been extensively verified with SCADA data in similar climates. Thus, the final uncertainty is sqrt (0.3^2 + 0.3^2 + 0.1^2) = 44 % of the absolute icing loss value.

9.2.0.4.2 Degradation

This loss represents blade fouling, efficiency losses and other performance degradation. Short term or cyclical blade fouling losses are due to insects, salt, and dirt sticking to the blades and cyclically and actively washed away by rain (or through blade cleaning). Long-term blade degradation is due to leading edge erosion from sand, debris, insects and hail/rain hitting (the rotating) blades, and temperature and icing cycles (freeze/thaw losses).

Performance degradation due to icing is considered in Section 4.1.2.5.1.

The uncertainty range typically considered is between 0.1% and 0.5%.

To evaluate the uncertainty of the degradation loss, the following must be considered:

D. Track record of critic.al components, primarily blades, in similar environments.

9.2.0.4.3 Environmental

Environmental shut down losses represent the losses due to turbine shut down caused by environmental conditions being outside the standard operating envelope of the equipment, including temperature, lightning, hail, and other environmental effects.

High temperature derating: In addition, turbines may be derated at temperatures below the high temperature shut down due to a cooling capacity reduction as detected by the turbine controller. Main driver is cable temperature which is influenced by ambient temperature, power (wind speed), air density, cos phi, grid voltage and the maintenance of the air inlet (including filters).

Low temperature derating: Turbines may be derated at cold temperatures to prevent damage by e.g. reduced oil viscosity or changes in material properties and to mitigate damage equivalent or extreme loads.

The uncertainty range typically considered is between 0.2% and 0.6%.

To evaluate the uncertainty of the environmental loss, the following must be considered:

- Details of the control strategy: where the provision of documentation on operation limits and cold/hot temperature derating for different grid voltages, cos phi and altitudes would be considered “medium understanding”(should we name this standard info?); if beyond that guarantees are put in place to compensate for derating losses by e.g. paying liquidated damages in case the guarantee is not met the details of the control strategy can be set to “high understanding”.

- availability of appropriate input data for implementing control strategy: the availability of on-site temperature data would be considered “medium” quality of input data, if beyond that information on cos phi and grid voltage is available the quality of input data can be set to “high”

- Track record of control strategy, where less than 20 turbine-years are considered “none” as per the uncertainty model, more than 20 turbine-years are considered an “average” track record and more than 50 turbine-years are considered a “strong” track record. Turbine-years is defined as number of operational years multiplied by the number of turbines.

9.2.0.4.4 Exposure changes

Tree growth or logging, residential or other building development, etc.

To evaluate the uncertainty of the exposure changes, the following must be considered:

- Accuracy of wind flow model with respect to exposure changes

- Quality of input data: the provision of an environmental study would be considered “medium” quality of input data as per the uncertainty model, if beyond that a detailed felling plan (if applicable) and settlement development plan (if applicable) for the project lifetime is provided the quality of input data can be set to “high”

9.2.0.5 Curtailments

Special operating modes have to be calculated according to the specific requirements of the wind farm project (e.g. WTG power output reduction due to loads and grid curtailment, noise emission, shadow flicker, bat protection and ice throw risk mitigation).

9.2.0.5.1 Loads Curtailment

Wind turbines may need to be curtailed for certain wind directions to mitigate excessive loads.

The uncertainty range typically considered is between 0.2% and 0.4%.

To evaluate the uncertainty of the loads curtailment loss the following must be considered:

- accuracy of required input data to calculate curtailment: where less than one year of wind data would be considered “poor”, the long-term wind rose determined from site met mast would be considered “standard” and at least 1 year of 10 minute measurements of wind speed, direction and TI at >2/3 HH used for curtailment calculation where wind speed and direction are long term corrected would be considered “good” as per the uncertainty model.
- completeness of information (control algorithm, etc.): where “standard info” as per the uncertainty model would be a curtailment strategy as well as cut-out and re-cut in for wind speed and wind direction at 10min resolution and “good info” would be higher resolution information of the control strategy provided, e.g. cut-out and re-cut in wind speed and direction at 10min, 5min and 3sec level or similar

9.2.0.5.2 Grid curtailment

This curtailment covers energy lost due to PPA/off-taker curtailments, or grid limitations.

The uncertainty range typically considered is between 0.1% and 0.5%.

To evaluate the uncertainty of the grid curtailment loss the following must be considered:

- Quality of grid study (strength of grid,.) and data completeness where a preliminary grid study e.g. a regional grid study would be considered “standard” quality and the final site specific grid reliability study would be considered “good” quality as per the uncertainty model. (grid connection agreement.)

9.2.0.5.3 Environmental/Permit Curtailment

This curtailment covers energy lost due to mitigation strategies with relation to wildlife protection (e.g. birds, bats, marine mammals), flicker and noise exposure and ice throw risk (when those are not captured in the power curve), etc.

The uncertainty range typically considered is between 0.3% and 0.5%.

To evaluate the uncertainty of the environmental/permit curtailment loss, the following must be considered:

- quality of input data: as per the uncertainty model would be
  - “poor” for
    - Noise: if turbine noise model is derived from noise modeling & some info is available,
    - Shadow Flicker: if Terrain and obstacles are not considered and generalized assumptions on solar radiation are used,
    - Wildlife: follow same thought process as for Noise and Shadow Flicker
  - “standard” for
    - Noise: if the turbine noise model is derived from noise modeling and all info (octave band etc.) is available,

        - Shadow Flicker: if calculated from a (frequency distribution derived from a) Time series of wind direction, solar radiation at hourly resolution and terrain and obstacles are considered,
        - Wildlife: follow same thought process as for Noise and Shadow Flicker
    - “good” for
        - Noise: if beyond standard the turbine noise model is derived & validated from noise measurements and all info is available
        - Shadow Flicker: If calculated from a time series with the following parameters: wind speed, wind direction, solar radiation at 10min resolution, the time series is made available and the calculation includes terrain and obstacles
        - Wildlife: follow same thought process as for Noise and Shadow Flicker
- completeness of information (control algorithm, etc.) where the availability of a detailed control strategy for e.g. noise, shadow and wildlife (information on which parameters trigger control strategy) would be considered “standard” information as per the uncertainty model, if beyond this a validation on the effectiveness of the control strategy is available the completeness of information can be set to “good”

9.2.0.5.4 Owner directed operational strategies

This curtailment covers energy lost or gained by any operational strategy that systematically or periodically modifies power output including owner-directed up-rating, down-rating or shut-down not captured in the power curve or availability carve-outs.

The uncertainty range typically considered is between 0.3% and 0.5%.

To evaluate the uncertainty of the owner directed operational strategies loss, the following must be considered:

• Track record and availability of performance validations, where less than 100 turbine years would be considered “none”, less than 500 turbine years would be considered an “average” and more than 500 turbine years a “good” track record as per the uncertainty model

• Completeness of information (control algorithm, etc.): If all information necessary to evaluate the operational strategy is available the completeness of information can be set to “strong” as per the uncertainty model.

9.3 Reporting Requirements

10 Historical Wind Resource Uncertainty

10.0 Historical Wind Resource

This section addresses uncertainty associated with estimating long-term mean annual wind speed.

10.0.0 Long-term Period

This is the uncertainty inherent is estimating the true mean wind speed at a target site using the mean wind speed of a reference period on. This uncertainty is represented as, s_{LT}

$$s_{LT} = \frac{IAV}{N_{LT}}$$

where IAV is interannual variability (aka coefficient of variation) of annual mean wind speeds, and N_{LT} is the long-term mean wind speed of a given reference data set. This assumes annual mean wind speeds fit a Gaussian distribution around the long-term mean wind speed. Reanalysis datasets under-estimate the variability of the annual mean wind speed from year-to-year and so should not be considered without adjustment using local measurements. The long-term period may be contaminated by changing data content over time for a variety of reasons, which may cause spurious trends. Potentially spurious trends should be investigated using comparable alternative data sources to avoid introducing error into the associated calculations. Data with spurious trends shall not be utilized.

In the absence of sufficient data to calculate site-specific s_{LT}, 6% shall be used.

10.0.1 Reference Data Consistency

This is the uncertainty arising from the risk of undetected non-climatic changes in the of long-term reference data. It is essential that a reference dataset is consistent over the reference period. Any detected inconsistency must be removed before use of the reference dataset, such that the reference period spanning the data adopted in the assessment is consistent.

Statistical methods for change point analysis are recommended with reference data consistency being related to the methodology adopted. Factors to be considered for change point analysis of ground-based references include changes over time in:

- Instrument type, quality (resolution), and calibration
- Mast installation (measurement height, orientation, etc.)
- Change in exposure (tree growth/felling, buildings, etc.)
- Measurement drift
- Maintenance and traceability
- Data coverage (data recovery)

Factors to be considered for change point analysis of re-analysis references include changes in:

- Model type and resolution
- variation in model inputs over time.
- drift over time

10.0.1.1 Calculation methods

While no accepted method of calculating a value of consistency uncertainty exists in the wind industry, a data consistency test (also termed homogeneity test) test or point analysis should be used to determine if heterogeneity exist in the data series under consideration. The Standard Normal Homogeneity Test (Alexandersson, H. A data homogeneity test applied to precipitation data. J. Climatol. 1986, 6, 661–675.) is one such test which can be used. In the absence of a quantitative analysis, a value of 2% shall be used.

10.0.2 Data Reconstruction

Data gaps, including those arising from the quality assessment and filtering, can introduce systematic errors in the measurement, especially if the gaps are not randomly distributed, but occur with accumulation in specific and not necessarily typical meteorological or climatologic situations (e.g. wintertime). Hence, data gaps of the relevant sensors may be filled by reconstruction of the missing data from measurement values of other sensors, in order to increase the data availability from the relevant sensors.

Relevant measurements include wind speed and wind direction. Further meteorological measurements may include temperature or pressure. Data filling may not be limited to sampling period mean values, but might also related to values such as standard deviation or maximum within each sampling period, depending on the purpose of the data for the further evaluation.

For gap filling, usually Measure-Correlate-Predict (MCP) procedures are applied in a similar manner as with long-term extrapolation, which is described in Section 10.0.3. The MCP procedures are preferably applied based on substantially similar datasets, e.g., data from two anemometers on the same mast with minimal deviation of the measurement heights, such that the scatter of the analysed data, and hence the uncertainties of the MCP application, are as small as possible. Generally, the requirements for the methodology and the application are comparable to those for the long-term extrapolation, so the description of Section 10.0.3 can be applied accordingly.

The result of the data filling process will consist of the filled time series of measurement data. To allow a critical asseessment of the uncertainties introduced by the data filling process, certain evaluations shall be performed, and the documentation of the data filling shall include the following:

- Specification of the overall number or percentage of the filled data.
- List of the main periods which re-filled (possibly per sensor),
- Evaluation of distribution of filled data (e.g. seasonal accumulation)
- Evaluation of the influence of the data filling on mean values and distributions of the relevant quantities, i.e. showing before and after the gap filling process
- Considerations of uncertainties resulting from the filling,
- Conclusions regarding usability or uncertainty of the filled data (of specific sensors)

This uncertainty considers to the strength of the relationship between target site measured data and reference data, as well as the uncertainty associated with the adjustment, or statistical extension, of target site-measured data to a long-term period. The following factors need to be considered:

- The temporal resolution used in the correlation of the target site and reference data
- Accuracy of the prediction model applied on the target site, as tested with a “predictability test” (i.e., boot strapping, analysis of variance, etc.)
- Representativeness of the concurrent measurement period (i.e., the length of concurrent data, seasonality)
- Amount of data that is reconstructed.

10.0.3 Long-term adjustment

Generally, the results of a wind measurement campaign at a wind farm site are valid only for the measurement period. Usually this is a short-term period of one or only a few years. Due to the fact that wind speed and wind direction distributions can show distinct inter-annual and seasonal variations, a database of many years is required in order to perform a reliable determination of the typical mean wind conditions, and hence for the determination of wind speed related site parameters or long-term annual energy yields. This, a long-term adjustment is required in order to project the measured data to long-term wind conditions which are considered to be representative for typical mean wind conditions.

This approach is based on the general assumption that a consistent long-term mean value of the wind conditions exist and can be derived from historic data, and that this mean value represents the best estimation for the future wind conditions. Thus, the derived results cannot take into account future changes like systematic climate change and the uncertainty associated with future changes is discussed in Section 10.1.

The aim of a long-term adjustment procedure is to determine the relationship between concurrent site and reference wind data and to apply the relationship for long-term extrapolation of the site data. The set of relevant parameters depend on different aspects such as the meteorological and topographic simulation and the time scale of the performed assessment. For typical wind energy related situations, the long-term extrapolation of wind speed and wind direction is necessary. Further meteorological parameters, like air temperature, should be taken into account for calculation of the long-term mean air density.

The concurrent data are analysed with respect to the relevant parameters, and appropriate models to describe the relationship are established. When defining the type of relationship, it must be taken into account, which properties of the wind distribution need to be modelled as not only the mean wind speed, but also the shape of the wind speed distribution is relevant. It might be required to consider a non-linear relationship between the data. If the quality of the reference data allows, the analysed data should have a high temporal resolution (at least hourly time series).

The application of a long-term extrapolation procedure shall include an assessment of the significance of the correlation coefficient. The applied method to determine the relationship must be well-defined and validated and an assessment of the procedure’s uncertainty by means of performed verifications shall be done.

An important prerequisite for performing a reliable long-term extrapolation is that there is a sufficient level of correlation between the site data and the reference data.

This uncertainty considers the strength of the relationship between target site measured data and reference data, as well as the uncertainty associated with the adjustment, or statistical extension, of target site-measured data to a long-term period. The following factors need to be considered:

- The temporal resolution used in the correlation of the target site and reference data
- Accuracy of the prediction model applied on the target site, as tested with a “predictability test” (e.g., boot strapping).
- Representativeness of the concurrent measurement period (i.e., the length of concurrent data, seasonality, similarity of concurrent wind speed and direction frequency distribution)
- Amount of data that is reconstructed.

10.0.3.1 Ensemble Approaches

The impact of ensemble approaches (whether they are “index” methods, or “multi-linear” regression methods, or other) shall be considered in a way that generally reduces the overall uncertainty.

10.1 Project Lifetime Variability

10.1.0 Modelled Operational Period

Uncertainty of the operational period, s_{op} is the uncertainty associated with how closely the wind resource over the evaluation period may match the long-term site average.

$$s_{op} = \frac{IAV}{\sqrt{N_{op}}}$$

where, IAV is the interannual variability of long-term mean wind speeds, and

N_{op} is the number of years in the operational period.

10.1.1 Climate Change

Where an impact of climate change can be assessed, then this may be considered as an uncertainty.

It is assumed that according to state-of-the-art methods, systematic trends or long-term oscillations of the wind conditions cannot be determined and modelled in such a way, which would lead to the prediction of the future wind conditions with higher accuracy. If an uncertainty is required to be incorporated in relation to climate change, then this is detailed in Section 10.1.1.

In the absence of site-specific quantification, a value of 1.5% shall be used.

10.1.2 Plant Performance

This is to account for the variability in plant losses, such as availability and environmental losses (icing).

11 Project Evaluation Period Variability Uncertainty

11.0 Measurement height wind regime

11.1 Hub height wind regime

11.2 Wind regime across the site

11.3 Power performance corrections

12 Site Measurement

Measurement Uncertainty

12.0 Introduction

The following guidelines for calculating the standard measurement uncertainty for resource assessments only apply by following the normative guidelines in the Annexes.

This guidance concerns measurement uncertainty arising during a Specific Measurement Campaign (SMC). This is a particular instance of a measurement system use case. Whereas the use case of the measurement system, such as a met tower or remote sensing device, describes a general measurement set up in terms of data requirements, measurement method and operational conditions, an SMC is a project specific instance of the use case at a particular time in a particular location under a particular set of conditions using a particular instrument set up according to a particular configuration to fulfil the data requirements of the use case for the purposes of a particular project.

IEC 61400-12-1, which provides a standard for power performance testing, has certain requirements for tower design, including tower top measurements with so-called “goal post” booms. For the purpose of pre-construction measurements, goal posts booms are not normative, and this section contemplates measurement meteorology towers without such sensor configurations, as well as measurement systems that are not tower-based, including remote sensing systems using laser, sound, or other measurement techniques. This approach is consistent with the more recent 61400-50 series of standards.

12.0.0 Approach

12.0.0.0 Outputs

Deliverable: uncertainty of validated series of each measurement at each relevant monitoring level, in percent of the observed parameter, (e.g., in percent wind speed for anemometers)

12.0.0.1 Framework

- Calculate uncertainty based upon contributions from:
  - Measurement Station – uncertainties associated with each measurement station location, orientation, site documentation, and system motion.
  - Monitoring Level Uncertainties – uncertainties associated with measurements and data processing at a single monitoring elevation, e.g., measurement volume terrain effects, combinations of wind speed measurements, etc.

- Sensor Measurement – uncertainties associated with individual sensors, including sensor specifications, mounting characteristics, data processing, and sensor-specific settings

12.0.0.2 Assumptions

- Raw data is assumed to be provided as observations with a specific sampling frequency, averaged to 10-minute statistics for wind speed and direction measurements; ancillary measurement parameters, e.g. air temperature, relative humidity, pressure, etc, may have less frequent observations but should identical averaging periods.
- Filtering of sensor data is carried out following manufacturers' recommendations.
- Boom vibrations assumed to be filtered and that any uncertainty caused by this phenomenon is not addressed
- Propagation of uncertainties is assumed to be by variance; Monte Carlo approaches are acceptable, but discussion and characterization of such are outside of this scope.

12.0.0.3 Limitations

Excludes:

- Rotor-equivalent wind speed is not addressed.
- Uncertainty for derived meteorological parameters, except air density
- Uncertainties associated with gaps in measurement records
- Synthetic observations for periods when a sensor is missing data, referred to as gap filling, period of record extension, data reconstruction, and similar.
- Scanning lidar
- Nacelle lidar
- Unmanned aerial vehicles
- Soundings

12.0.1 Overall Process Description

udVS,i Documentation and verification
uVS,i Sensor measurement uncertainty

12.1 Data Integrity and Documentation

12.2 Sensor Measurement Uncertainty

12.2.0 Wind Speed Sensors

This uncertainty component covers the uncertainty related to the use of cup anemometers and sonic anemometers in meteorological masts (either top mounted or side mounted). The symbol for this uncertainty component is $u_{VS,i}$. (V stands for wind speed and S stands for sensors).

This uncertainty component has six subcomponents and can be calculated according to the following formula:

$$u_{VS,i} = \sqrt{u_{VS,precal,i}^2 + u_{VS,postcal,i}^2 + u_{VS,class,i}^2 + u_{VS,mnt,i}^2 + u_{VS,lgt,i}^2 + u_{dVS,i}^2}$$

where

$u_{VS,precal,i}$ is the uncertainty related to the calibration of the sensor that could be before or after the start of the measurement campaign;

$u_{VS,postcal,i}$ is the uncertainty related to the calibration of the sensor during or after the power performance test;

$u_{VS,class,i}$ is the uncertainty related to the classification of the sensors;

$u_{VS,mnt,i}$ is the uncertainty related to the mounting of the sensors;

$u_{VS,lgt,i}$ is the uncertainty related to the flow distortion from objects that could cause flow distortion (e.g. lightning finial, bat sensors, marker balls, lighting etc);

$u_{dVS,i}$ is the uncertainty related to the data acquisition of the wind speed signal

12.2.0.0 Uncertainty related to the calibration of the sensor

Category B uncertainties: Wind speed – Met mast sensors – Pre-calibration (see (IEC, 2017) E.6.3.2 and Annex F)

This uncertainty component covers the uncertainty related to calibration of the sensor. The calibration could be pre- and/or post- the measurement campaign period. This includes the variability of repeated tests for one test facility as well as the variability of repeated tests between various facilities. It is strongly recommended that anemometry is calibrated at a MEASNET and ISO 2009 accredited facility.

The symbol for this uncertainty component is $u_{V,S,cal,i}$.

For resource assessments, the values as indicated on each anemometer calibration certificate for the sensors employed shall be used for the uncertainty calculation.

This uncertainty component covers the uncertainty related to the in-situ calibration and/or the post-calibration of the sensor during and/or after the test.

The symbol for this uncertainty component is $u_{V,S,postcal,i}$.

This uncertainty is also discussed in (IEC, 2017) chapter 7.2.2 and Annex K.

If both an in-situ calibration has been done during the resource assessment measurement as well as a post-calibration has been done after the resource assessment measurement, the magnitude for this uncertainty component shall be taken from the post-calibration.

If a post calibration is done, the magnitude of this uncertainty component shall be the maximum difference between the pre-calibration and post-calibration in the wind speed range of 4 m/s to 12 m/s, up to a maximum of **0.2 m/s**.

Please note that due to the inherent uncertainty of the calibration the expectation will be that small differences will occur between the pre-calibration and post-calibration. The best estimate of the calibration value for a specific sensor will be the average of the calibrations done; in the limit of a very large number of calibrations the average will converge towards the centre of the distribution.

As only the pre-calibration is used to determine the wind speed from the sensor, the maximum difference can therefore be used as an added uncertainty contribution.

If only an in-situ calibration is done according to IEC 61400-50-1, the magnitude of this uncertainty component shall be the maximum value of δ in the wind speed range of 4 m/s to 12 m/s, up to a maximum of **0.2 m/s**.

12.2.0.1 Uncertainty related to the operational characteristics as determined by the classification of the sensor

(E.6.3.4 Category B uncertainties: Wind speed – Met mast sensors – Classification)

This uncertainty component covers the uncertainty related to the operational characteristics of the sensor as determined by the classification of the sensor.
The symbol for this uncertainty component is $u_{V,S,class,i}$.

This uncertainty is also discussed in IEC 61400-50-1 Chapter 6.
The magnitude of this uncertainty shall be taken from the classification report. Care shall be taken that the terrain type and temperature range the sensor is used in matches the terrain type and temperature range of the classification of the sensor (Class A, B, C, D or S).

A reference to the classification report shall be included in the final report of the whole measurement period.

The formula (see IEC 61400-50-1 Chapter 6) for this uncertainty component is the following:

$$u_{v2j} = \left(0{,}05\frac{m}{s} + 0.005 * \ U_j\right) * k\sqrt{3}$$

Where,

k: Classification factor e.g. k=1,7 for class 1,7A
U_j: is the wind speed in m/s for influence parameter combination j.

12.2.0.2 Uncertainty related to the mounting of the sensor;

(E.6.3.5 Category B uncertainties: Wind speed – Met mast sensors – Mounting)

This uncertainty component covers the uncertainty related to the mounting of the sensor. The symbol for this uncertainty component is $u_{V,S,mnt,i}$.

This uncertainty is also discussed in IEC 61400-50-1 Chapter 10, 11.3.5, and Annex B

This uncertainty component has three default values corresponding to the three mounting arrangements allowed by IEC 61400-50-1 Chapter 10 (single top- mounted anemometer, side-by-side top- mounted anemometers or side-mounted anemometer).

For a single top-mounted anemometer, the default magnitude for this uncertainty component is 0.5 % of the measured wind speed.

For a side-by-side top-mounted anemometer, the default magnitude for this uncertainty component is 1.0 %.

For a side-mounted anemometer, the default magnitude for this uncertainty component is one the following:

- for not-flow-corrected signals the default magnitude for this uncertainty component is 1,5 % of the measured signal;

- for a flow-corrected signal according to IEC 61400-50-1 Chapters 10.4.3 and 11.4.3 the default magnitude for this uncertainty component is the root-sum-square of half the mean correction applied to the wind speed signal and 0,5 % of the measured signal. Wake effects shall be excluded for the correction to be applied.

The same correction principle can also be applied to two top-mounted anemometers in a goal- post configuration, with the same default magnitude for the flow-corrected signal.

12.2.0.3 Uncertainty related to the mounting of the lightning finial

(E.6.3.6 Category B uncertainties: Wind speed – Met mast sensors – Lightning finial)

This uncertainty component covers the uncertainty related to a possible lightning finial and its influence on an anemometer.
The symbol for this uncertainty component is $u_{V,S,lgt,i}$.

The default magnitude for this uncertainty component is 0,1 % to 0,2 % of the wind speed signal.

12.2.0.4 Uncertainty related to the data acquisition of the signal from the sensor

(E.6.3.7 Category B uncertainties: Wind speed – Met mast sensors – Data acquisition)

This uncertainty component covers the uncertainty related to the data acquisition of the wind speed signal.

The symbol for this uncertainty component is $u_{dV,S,i}$.

This uncertainty is also discussed in IEC 61400-50-1 Chapter 10.7.

The default magnitude for this uncertainty component is 0,1 % to 0,2 % of the full range of the measured wind speed signal.

Considering a wind speed range of 30 m/s of the measurement channel and an uncertainty of the data acquisition system of 0,1 % of this range, the standard uncertainty from data acquisition is 0,03 m/s.

12.2.1 Wind Direction Sensors

There is an influence of the wind direction uncertainty on the AEP calculation. Based on the magnitude of the wind direction uncertainty , some data will be incorrectly assigned to a bin. For a bin size of 10° and a wind direction uncertainty of 5°, roughly 39 % of the data in a bin has been wrongly assigned. Although this will tend to average out, it can have an effect for small measurement sectors and large differences between adjacent bins. A similar argument applies to the filtering on the power curve measurement sector, but to a lesser extent. This background is the main reason why the IEC 61400-50-1 standard requires that the wind direction uncertainty is assessed to ensure that it <u>stays below 5°.</u>
The influence from the wind direction on the power curve and AEP is not quantifiably established and no sensitivity factors have been developed.
As the wind direction uncertainty shall be reported, (IEC, 2017) Clause E.12 gives the minimum uncertainty components that shall be considered for the wind direction uncertainty.
The following uncertainty components are combined to calculate the category B uncertainty for the wind direction measurement with wind vane or sonic anemometer, $u_{WV,i}$:

$$u_{WV,i} = \sqrt{u_{WV,cal,i}^2 + u_{WV,nm,i}^2 + u_{WV,bo,i}^2 + u_{WV,oe,i}^2 + u_{WV,mda,i}^2 + u_{dWV,i}^2}$$

where

$u_{WV,i}$ is the uncertainty related to the wind direction measured with a mast mounted wind direction sensor (wind vane or sonic anemometer);
$u_{WV,cal,i}$ is the uncertainty related to the calibration of the wind direction sensor;
$u_{WV,nm,i}$ is the uncertainty related to north marking of the wind direction sensor;
$u_{WV,bo,i}$ is the uncertainty related to the boom orientation on which the wind direction sensor is mounted;
$u_{WV,oe,i}$ is the uncertainty related to the influence of the meteorological mast on the wind direction measurement;
$u_{WV,mda,i}$ is the uncertainty related to the magnetic declination angle;
$u_{dWV,i}$ is the uncertainty related to the data acquisition of the signal from the wind direction sensor.

12.2.1.0 Uncertainty related to the calibration of the wind direction sensor

(E.12.2.1 Category B uncertainties: Wind direction – Vane or sonic – Calibration)

This uncertainty component covers the uncertainty related to the calibration of the wind direction sensor.

The symbol for this uncertainty component is $u_{WV,cal,i}$.

The resolution of the wind direction sensor is also included here and this value divided by $2\sqrt{3}$ shall be taken as a minimum value.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.1.1 Uncertainty related to north marking of the wind direction sensor

(E.12.2.2 Category B uncertainties: Wind direction – Vane or sonic – North mark)

This uncertainty component covers the uncertainty related to the accurate determination of the sensors north mark in relation to the boom on which the sensor is installed.

The symbol for this uncertainty component is $u_{WV,nm,i}$.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.1.2 Uncertainty related to the boom orientation on which the wind direction sensor is mounted

(E.12.2.3 Category B uncertainties: Wind direction – Vane or sonic – Boom orientation)

This uncertainty component covers the uncertainty related to establishing the direction of the boom with regards to the North reference, i.e. magnetic or true.

The symbol for this uncertainty component is $u_{WV,bo,i}$.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.1.3 Uncertainty related to the influence of the meteorological mast on the wind direction measurement

(E.12.2.4 Category B uncertainties: Wind direction – Vane or sonic – Operational effects)

This uncertainty component covers the uncertainty related to the influence of the mast on the free stream wind direction at the point of measurement.

The symbol for this uncertainty component is $u_{WV,oe,i}$.

As the wind will flow around the mast, the wind direction as measured by the sensor may not be the free flow wind direction. This effect is covered under this uncertainty component.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.1.4 Uncertainty related to the magnetic declination angle

(E.12.2.5 Category B uncertainties: Wind direction – Vane or sonic – Magnetic declination angle)

This uncertainty component covers the uncertainty related to the difference between magnetic north and true north.

The symbol for this uncertainty component is $u_{WV,mda,i}$ (MDA stands for magnetic declination angle).

The correction from magnetic north to true north is also related to an uncertainty.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.1.5 Uncertainty related to the data acquisition of the signal from the wind direction sensor

(E.12.2.6 Category B uncertainties: Wind direction – Vane or sonic – Data acquisition)

This uncertainty component covers the uncertainty related to the data acquisition of the signal from the wind direction sensor.

The symbol for this uncertainty component is $u_{dWV,i}$.

No default value is given but this uncertainty component shall be assessed and reported.

12.2.2 Air density calculation

This uncertainty component covers the uncertainty related to the influence of air density on the AEP.
The symbol for this uncertainty component is $u_{AD,i}$.
The air density is derived from measurements of the air temperature, the humidity and the air pressure.

The air density uncertainty consists of four components:

a) the uncertainty related to the use of a temperature sensor and the data acquisition;

b) the uncertainty related to the use of a pressure sensor and the data acquisition;

c) the uncertainty related to the use of a relative humidity (RH) sensors and the data acquisition, or the lack of such a sensor;

d) the uncertainty due to the air density correction.

12.2.2.0 Uncertainty related to the use of a temperature sensor and the data acquisition

(E.10.2 Category B uncertainties: Air density – Temperature introduction)

This uncertainty component covers the uncertainty related to the measurement of the temperature.

The symbol for this uncertainty component is $u_{T,i}$.and is calculated according to the following formula:

$$u_{T,i} = \sqrt{u_{T,cal,i}^2 + u_{T,shield,i}^2 + u_{T,mnt,i}^2 + u_{dT,i}^2}$$

Where,

$u_{T,i}$. is the uncertainty of the temperature measurement;

$u_{T,cal,i}$. is the uncertainty related to the calibration of the temperature sensor;

$u_{T,shield,i}$. is the uncertainty related to the shielding of the temperature sensor;

$u_{T,mnt,i}$ is the uncertainty related to the mounting of the temperature sensor;

$u_{udT,i}$. is the uncertainty related to the data acquisition of the temperature signal.

<u>Example calculation:</u> If we make the following assumptions:

- The standard uncertainty of the temperature sensor is 0,5 °C.
- The shielding of the temperature sensor is 2 °C.
- The standard uncertainty due to mounting effects of the temperature sensor is dependent on the vertical distance from the hub height. With the temperature sensor mounted within 10 m of hub height a standard uncertainty of 1/3 °C is assumed.
- Considering a temperature range of 40 °C of the measurement channel and a standard uncertainty of the data acquisition system of 0,1 % of this range.

Then the numerical calculation for the standard uncertainty of the air temperature in each bin is:

$$u_{T,i} = \sqrt{(0{,}5K)^2 + (2{,}0K)^2 + (0{,}3K)^2 + (0{,}1\% * 40K)^2} = 2{,}1K$$

12.2.2.0.1 Uncertainty related to the calibration of the temperature sensor

(E.10.3 Category B uncertainties: Air density – Temperature – Calibration)

This uncertainty component covers the uncertainty related to the calibration of the temperature sensor.

The symbol for this uncertainty component is $u_{T,cal,i}$.

The default magnitude for this uncertainty component is 0,4 °C to 0,6 °C.

12.2.2.0.2 Uncertainty related to the radiation shielding of the temperature sensor

(E.10.4 Category B uncertainties: Air density – Temperature – Radiation shielding)

This uncertainty component covers the uncertainty related to the radiation shielding of the temperature sensor.

The symbol for this uncertainty component is $u_{T,shield,i}$..

The default magnitude for this uncertainty component is 1,5 °C to 2,5 °C.

12.2.2.0.3 Uncertainty related to the mounting of the temperature sensor

(E.10.5 Category B uncertainties: Air density – Temperature – Mounting)

This uncertainty component covers the uncertainty related to the mounting of the temperature sensor.

The symbol for this uncertainty component is $u_{T,mnt,i}$..

The default magnitude for this uncertainty component is 0,25 °C to 0,4 °C.

12.2.2.0.4 Uncertainty related to the data acquisition of the signal from the temperature sensor

(E.10.6 Category B uncertainties: Air density – Temperature – Data acquisition)

This uncertainty component covers the uncertainty related to the data acquisition of the signal of the temperature sensor.

The symbol for this uncertainty component is $u_{dT,i}$..

The default magnitude for this uncertainty component is 0, 1 % to 0,2 % of the full range of the measurement channel. With an assumed temperature range of 40 °C this comes to 0,04 °C.

12.2.2.1 Uncertainty related to the use of a pressure sensor and the data acquisition

(E.10.7 Category B uncertainties: Air density – Pressure introduction)

This uncertainty component covers the uncertainty related to the measurement of the pressure.

The symbol for this uncertainty component is $u_{B,i}$.and is calculated with the following formula:

$$u_{B,i} = \sqrt{u_{B,cal,i}^2 + u_{B,mnt,i}^2 + u_{dB,i}^2}$$

Where,

$u_{B,i}$	is the uncertainty of the pressure measurement;
$u_{B,cal,i}$	is the uncertainty related to the calibration of the pressure sensor;
$u_{B,mnt,i}$	is the uncertainty related to the mounting of the pressure sensor;
$u_{dB,i}$	is the uncertainty related to the data acquisition of the pressure signal.

If we make the following assumptions:

- The pressure sensor to have a standard uncertainty of 3,0 hPa. It is assumed that the pressure is corrected to the hub height according to ISO 2533 (which, for a standard atmosphere and a height difference of 98 m between the sensor and the hub, is 11,7 hPa). The standard uncertainty due to deployment is estimated to be 10 % of the correction, which is 1,17 hPa.

- Considering a pressure range of 100 hPa of the measurement channel and a standard uncertainty of the data acquisition system of 0,1 % of this range.

Then the numerical calculation for the standard uncertainty of the air pressure is:

$$u_{B,i} = \sqrt{(3{,}0hPa)^2 + (1{,}17hPa)^2 + (0{,}1\% * 100hPa)^2} = 3{,}2hPa$$

12.2.2.1.1 Uncertainty related to the calibration of the pressure sensor

(E.10.8 Category B uncertainties: Air density – Pressure – Calibration)

This uncertainty component covers the uncertainty related to the calibration of the pressure sensor.

The symbol for this uncertainty component is $u_{B,cal,i}$.

The default magnitude for this uncertainty component is **2 hPa to 4 hPa**.

12.2.2.1.2 Uncertainty related to the mounting of the pressure sensor

(E.10.9 Category B uncertainties: Air density – Pressure – Mounting)

This uncertainty component covers the uncertainty related to the mounting of the pressure sensor.

The symbol for this uncertainty component is $u_{B,mnt,i}$.

The default magnitude for this uncertainty component is determined by the height difference for which the signal from the pressure sensor is corrected. Using ISO 2533 the pressure related to this height difference can be calculated. The default magnitude for the uncertainty related to this pressure correction is **10 % of the correction**.

For a sensor installed at a height of 2 m and a hub height of 100 m, the difference is 98 m which gives a pressure difference of 11,7 hPa. The uncertainty would then be 1,17 hPa.

12.2.2.1.3 Uncertainty related to the data acquisition of the signal from the pressure sensor

(E.10.10 Category B uncertainties: Air density – Pressure – Data acquisition)

This uncertainty component covers the uncertainty related to the data acquisition of the signal of the pressure sensor.

The symbol for this uncertainty component is $u_{dB,i}$.

The default magnitude for this uncertainty component is 0.1 % of the full range of the measurement channel for pressure. Considering a pressure range of 100 hPa of the measurement channel this gives 0.1 hPa.

12.2.2.2 Uncertainty related to the use of relative humidity (RH) sensors and the data acquisition, or the lack of such sensors

(E.10.11 Category B uncertainties: Air density – Relative humidity introduction)

This uncertainty component covers the uncertainty related to the measurement of the relative humidity. The relative humidity is not required to be measured. In that case, a default value of 50 % shall be assumed with an uncertainty of 100 % (from 0 % to 100 %).

The symbol for this uncertainty component is $u_{RH,i}$ .and its formula is:

$$u_{RH,i} = \sqrt{u_{RH,cal,i}^2 + u_{RH,mnt,i}^2 + u_{dRH,i}^2}$$

In case the humidity is measured, this uncertainty component has three sub-components:

uRH,i	is the uncertainty of the relative humidity measurement;
uRH,cal,i	is the uncertainty related to the calibration of the relative humidity sensor;
uRH,mnt,i	is the uncertainty related to the mounting of the relative humidity sensor;
udRH,i	is the uncertainty related to the data acquisition of the relative humidity signal.

If we make the following assumptions:

• The relative humidity sensor to have a standard uncertainty of 1 %;
• The mounting of the sensor to be 0.1 %;
• Considering a pressure range of 100% of the measurement channel and a standard uncertainty of the data acquisition system of 0.1 % of this range.

Then the numerical calculation for the standard uncertainty of the relative humidity is:

$$u_{RH,i} = \sqrt{(1{,}0\%)^2 + (0{,}1\%)^2 + (0{,}1\% * 100\%)^2} = 1{,}0\%$$

12.2.2.2.1 Uncertainty related to the calibration of the humidity sensor

(E.10.12 Category B uncertainties: Air density – Relative humidity – Calibration)

This uncertainty component covers the uncertainty related to the calibration of the humidity sensor.

The symbol for this uncertainty component is $u_{RH,cal,i}$.

The default magnitude for this uncertainty component is 1 % to 2 %.

12.2.2.2.2 Uncertainty related to the mounting of the humidity sensor

(E.10.13 Category B uncertainties: Air density – Relative humidity – Mounting)

This uncertainty component covers the uncertainty related to the mounting of the humidity sensor.

The symbol for this uncertainty component is $u_{RH,mnt,i}$.

The default magnitude for this uncertainty component is 0,1 % to 0,2 % of the measured value.

12.2.2.2.3 Uncertainty related to the data acquisition of the signal from the humidity sensor

(E.10.14 Category B uncertainties: Air Density – Relative humidity – Data acquisition)

This uncertainty component covers the uncertainty related to the data acquisition of the signal from the humidity sensor.

The symbol for this uncertainty component is $u_{dRH,i}$.

The default magnitude for this uncertainty component is 0,1 % of the full range of the measurement channel for relative humidity.

12.2.2.3 Uncertainty related to the correction of air density

(E.10.15 Category B uncertainties: Air density – Correction)

This uncertainty component covers the uncertainty related to the air density correction.

The symbol for this uncertainty component is $\mathrm{u}_{\mathrm{AD,method,i}}$

As part of the data analysis, a normalisation from measured air density to a reference air density is performed. This normalisation is related to an uncertainty component, in part because of the uncertainties in the measured temperature, pressure and relative humidity but also because one of the underlying assumptions upon which the normalisation formula is based is increasingly inaccurate the larger the air density difference is on which the air density normalisation is applied.

12.3 Remote Sensing Device Measurement Uncertainty

Remote Sensing Devices (RSDs) or Remote Sensors (RS) including sodar and lidar are used for measurements of wind speed, wind direction, vertical wind speed, and turbulence intensity. These different measurements are typically generated using the same database of high frequency (0.2 Hz – 50 Hz) line-of-sight (LOS) measurements reconstructed to 10-minute averages.

This section outlines the uncertainty components and calculation of the uncertainty level associated with reconstructed RSD measurements. These uncertainties can be applied to different measurements generated by RSDs, including:

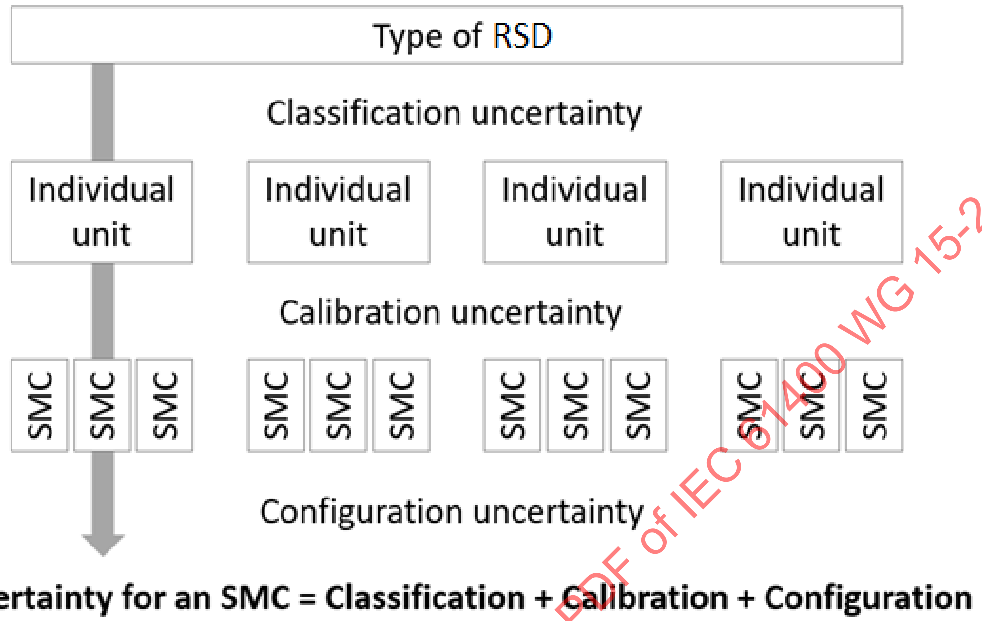
- Wind speed
- Wind direction
- Vertical wind speed component
- Standard deviation of horizontal wind speed component
- Turbulence intensity
- Standard deviation of vertical wind speed component
- Extreme wind speed within 10-minute period

12.3.0 Those derivative, post-processed, or composite values described in section 1.1.4 are outside the scope of this standard. Generalized uncertainty components for RSD measurement campaigns

This uncertainty component covers the uncertainty related to the RSD for an SMC. For different measurements using the same LOS data, specific instances of these general uncertainties are described in sections 9.4.2 – 9.4.10.

12.3.0.0 Hierarchy of Uncertainties

Contributions to the measurement uncertainty budget fall into three broad categories, which form a hierarchy of uncertainties associated with classification, calibration and configuration, that address the performance of a type of instrument, the performance of a specific unit of that type, and the performance of that unit during a specific measurement campaign, respectively. This is illustrated in the diagram below.



The uncertainty estimates to be applied to measurements obtained during a specific measurement campaign is derived by combining contributions to uncertainty associated with:

- The sensitivity of the accuracy of units of that type to the values of environmental variables observed during the specific measurement campaign, evaluated in accordance with the guidance on classification described in IEC 61400-50-2, Chapter 6
- The performance of the individual unit deployed during the specific measurement campaign, with respect to accuracy, as determined during calibration according to the guidance on calibration described in IEC 61400-50-2, Chapter 7 for verifications carried out using met masts, and in this document Annex A.2, Calibrations Using Remote Sensing Devices.
- The extent to which the configuration of the unit during the specific measurement campaign replicates the way it was installed and operated during its calibration, in accordance with guidance on installation and operation described in IEC 61400-50-2, Chapter 9.
- The results of the post-validation to determine if there is systematic drift in the device.

Therefore, the uncertainty budget can be expressed as follows:

$$U_{RSD}^2 = U_{Cla}^2 + U_{Cal}^2 + U_{Con}^2 + U_{PostCal}^2$$

Where:
U_{RSD} is the uncertainty to be applied to RSD measurements
U_{Cla} is the classification uncertainty
U_{Cal} is the calibration uncertainty
U_{Con} is the configuration uncertainty
$U_{PostCal}$ is the post-calibration uncertainty

The classification uncertainty may be zero if no observed environmental sensitivities exist as described in IEC 61400-50-2, Chapter 6.5.

The calibration (or verification) uncertainty will always be non-zero. The calibration uncertainty can be interpreted as the intrinsic uncertainty of the instrument.

The configuration uncertainty may be zero if the requirements of [CHAPTER X.X] are fulfilled and none of the sources of configuration uncertainty described below are incurred.

The *in situ* or post-calibration (or verification) uncertainty may be zero if no deviation from the calibration is observed.

12.3.0.1 General Uncertainties for Energy Yield Assessment Measurement Campaigns

The below uncertainties are described in IEC 61400-50-2 :

- $u_{\mathrm{GR,class}}$ uncertainty of RSD classification (equivalent to U_{Cla})
- $u_{\mathrm{GR,ver}}$ uncertainty of RSD verification (component of U_{Cal})
- $u_{\mathrm{GR,post}}$ uncertainty of RSD in situ or post-verification (component of U_{Cal})

Configuration uncertainty has subcomponents:

$$U_{Con}^2 = u_{GR,flow}^2 + u_{GR,mount}^2 + u_{GR,D}^2 + u_{GR,adj}^2 + u_{GR,DF}^2$$

Also described in IEC 61400-50-2:

- $u_{\mathrm{GR,flow}}$ uncertainty of flow complexity within the measurement volume
- $u_{\mathrm{GR,adj}}$ uncertainty of measurement adjustment
- $u_{\mathrm{GR,mount}}$ uncertainty of mounting effect
- $u_{\mathrm{GR,D}}$ uncertainty of RSD deployment documentation and verification

G subscript indicates these are Generalized and can be applied to any of the measurements listed above (e.g. wind speed, wind direction, turbulence intensity) if there is a need in AEP estimation. R subscript indicates Remote Sensing Device.

Note that the applicability of individual uncertainty components and contributions may be use case- or measurement-dependent. For example, the contribution of nonhomogeneous flow to verification uncertainty may be zero in wind speed measurements in simple terrain or offshore but non-zero and of critical importance for complex terrain.

12.3.1 RSD wind speed measurements

12.3.1.0 Classification

This uncertainty component covers the uncertainty related to the result of the classification of the remote sensing device for wind speed.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR,class}}$

The calculation of this uncertainty is covered in IEC 61400-50-2, *Chapter 6, Classification of Remote Sensing Devices*.

12.3.1.1 Verification

This uncertainty component covers the uncertainty related to the result of the verification of RSD wind speed measurements. The terms “Verification” and “Calibration” when referring to overall processes are equivalent. The specific application of calibration values derived from these processes varies depending on the SMC and Use Case.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR,ver}}$

12.3.1.1.1 Meteorological mast verification

For verifications using co-located met mast anemometry, the calculation of this uncertainty using a collocated met mast is covered in IEC 61400-50-2, *Chapter 7, Verification of the performance of remote sensing devices* with the following changes:

- Wind speed range 4 m/s to 12 m/s, inclusive

12.3.1.1.2 RSD verification

For verifications using a reference remote sensing device, RSD_{Ref} (referred to as a “golden” or “master” RSD), the reference RSD must itself have been calibrated to calibrated reference sensors on a met mast.

The suitability of the RSD as a reference relies on operational conditions being equivalent in all respects relevant to measurement accuracy to the conditions prevailing during its own calibration, such that equivalent performance with respect to accuracy may reasonably be anticipated.

The verification test shall be performed for each individual RSD unit.

In the case of significant deviations of the measurements of the RSD and the reference sensors, possible reasons for deviations shall be investigated.

If the RSD measurements agree with the reference sensors within the key performance indicators thresholds, the transfer functions as derived from the comparison of the reference sensors to RSD measurements should be applied, and the evaluation of the verification test shall be repeated with the corrected data of the RSD.

The verification of the RSD should be performed in such a way that the RSD configuration during the verification test is close to the RSD configuration during the measurement campaign. The verification test according to IEC 61400-50-2, Ed. 1 may be performed for

- Wind speed
- Wind direction
- Standard deviation of horizontal wind speed component
- Turbulence intensity
- Vertical wind speed component
- Standard deviation of vertical wind speed component
- Wind speed ratio at two height levels, e.g. wind speed at hub height divided by wind speed at highest measurement height of an adjacent measurement mast
- Wind shear
- Wind veer
- Vertical flow inclination
- Extreme wind speed within 10-minute period

In the case that an RSD is applied for turbulence measurements, at least the verification test shall be performed also for the turbulence intensity, and the results shall prove the capability of the instrument for such measurements.

12.3.1.1.3 Height of measurement for verification

It is pointed out that the uncertainty of an RSD can be dependent on the measurement height, so the requirements of the IEC 61400-50-2, Ed. 1 regarding heights used for the verification test shall be applied.

Specific heights conditions apply for the classification and verification of the RSD. These are described in IEC 61400-50-2, Ed. 1. One of these conditions is that “*A remote sensing device classification and verification shall be considered valid for the purposes of a power curve test of a wind turbine if the reference cup anemometers used during the classification and verification tests were mounted at a minimum of 3 heights, including the lower tip height of the wind turbine +/- 25 % and the hub height of* *the wind turbine +/- 25 %."* Similar condition should be applied although the validity must be based on an estimation of the height of the wind turbines model which could be chosen for the project: if the RSD is calibrated at a height lower than 0.75 times the expected height of the wind turbines therefore an uncertainty of calibration uncertainty extrapolation should be considered.

This uncertainty is non-zero only if an inconsistency is observed over the height of measurement of the RSD. Specifically, if the calibration uncertainties of the lidar are significantly different at two different heights, then the uncertainty of calibration uncertainty extrapolation is considered non null. A typical threshold to identify inconsistency could be the k 1 uncertainty of calibration reduced by mean deviation (IEC61400-50-2 Ed. 1, Annex L), typically composed of reference uncertainty, mounting uncertainty and statistical uncertainty. A typical value could be 1.5%.

The calculation of this uncertainty of calibration uncertainty extrapolation is based on an extrapolation of the calibration uncertainties at the specific measurement campaign height (expected hub height of the wind turbines for example). The extrapolation method depends on the model that can be applied to fit the calibration uncertainties. Linear regression is nonetheless recommended when possible.

If non zero, this added uncertainty should added to $u_{\mathrm{VR,ver}}$ in quadrature.

12.3.1.1.4 Testing laboratory accreditation

These tests should be prepared by independent companies having extensive experience in wind measurements, RSD and with the performance of such tests.

12.3.1.1.5 Frequency of pre-verification

The verification of the RSD should be performed at most 1 year prior to the start of the measurement campaign. Failure in calibrating at the prescribed timeline results in an uncertainty penalty according to the following rule:

- Each month separating the start of the campaign and the verification date should account for an uncertainty equivalent to 2% divided by the service interval rounded to two decimal places.
- This does not account for the 1-year period prior to the start of the campaign. Each month started accounts for an entire month.

Example: The RSD service interval is 3 years. The penalty per month is 2% divided by 36 months (0.06% per month).

- RSD is calibrated on July 15, 2019
- Campaign starts on September 20, 2020

Campaign Start Date Ranges After Verification	**Added uncertainty**
July 15, 2019 to July 15, 2020	0%
July 16, 2020 to August 16, 2020	0.06%
August 16, 2020 to September 16, 2020	0.12%
September 16, 2020 to October 16, 2020	0.18%

.

If non-zero, this added uncertainty should added to $u_{\mathrm{VR,ver}}$ in quadrature.

12.3.1.2 Measurement control

This uncertainty component covers the uncertainty related to the result of the post verification of the remote sensing device or to the result of the monitoring of the remote sensing device.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR\ postver}}$ if post verification is carried out or . $u_{\mathrm{VR,\ isc}}$ if monitoring of the remote sensing device is carried out.

IEC 61400-50-2, Ed. 1 requires a monitoring of the RSD measurements with a control mast with a minimum height of 40 m or the lower tip height of the considered type of wind turbine. The purpose is to check the data for consistency, caused e.g., by a drift or outliers in the data of the RSD or systematic effects because of absent data. This campaign configuration may be used directly for wind resource assessment.

Contrary to IEC 61400-50-2, Ed. 1, this standard allows for monitoring to be substituted by performing a second verification test after the measurement campaign. provided the project site and the verification site are assessed as not complex in accordance with IEC 61400-1 Section 11.2.1.

Standalone RSD measurements are permitted if:

- The lidar is verified before and after the measurement campaign
- The project site and verification site are equivalent. Equivalence is established if:
    - both sites are classified as “not complex” according to Table 5 in IEC 61400-1:2019.
    - both sites share the same “complex” category according to Table 5 in IEC 61400-1:2019, and an evidence base exists demonstrating the uncertainties of RSD measurements generated using a combination of a suitable flow model and the wind field reconstruction algorithm in comparison to collocated *in situ* reference sensors
- The surface conditions beneath the measurement volume are uniform at both sites

Monitoring or post-calibration uncertainty is non-null only if the mean deviation obtained from the comparison to the reference is inconsistent with pre-verification results or if significant and unexplained drift is observed.

12.3.1.2.1 Post-verification method and uncertainty

The circumstances of the post-verification should replicate as closely as possible the circumstances of the SMC, to ensure the performance of the instrument with respect to accuracy observed at the post-verification test site may be considered representative of its performance during the SMC. In particular, the instrument configuration implemented during the SMC should be reproduced during post-verification. The test site should not introduce any influences on accuracy that were absent during the SMC. This ensures discrepancies in performance observed during post-verification can be attributed to the configuration used during the SMC as confidently as possible.

For example, in relation to instrument configuration, to following attributes of the SMC should be replicated during post-verification (non-exhaustive list):

- Firmware;
- Installation procedure (to establish location and orientation relative to the target measurement volume within the same tolerances);
- In the case of programmable devices, the same configuration.

Examples of variations between SMC and post-verification that can be accepted include (but are not limited to) power supply and communications system.

In relation to the post-verification test site, characteristics that influence flow complexity that may in turn have implications for wind field reconstruction (WFR) should be replicated, or where they differ, a technical rationale should be provided regarding why the difference may be disregarded. For example:

- Orographic complexity of the SMC site terrain should be replicated by the post-verification test site.

The degree of surface roughness may be disregarded in the case of uniform roughness within reasonable limits. However, variations in surface type may be significant if this leads to differential surface heating that introduces convective influences on flow complexity.

12.3.1.2.2 Measurement control method and uncertainty

The post-verification should be carried out at an accredited test site, calculating the uncertainty and mean deviation from the reference following the method described in IEC 61400-50-2 (the same style of analysis used for the verification test) These need not be carried out at the same site, not following exactly the same methodology, provided both are carried out following the 50-2.

If the unadjusted pre- and post-verification are both within the uncertainty bounds of the verification tests, U_{PostCal} is zero.

If the unadjusted pre- and *in situ* verification are both within the uncertainty bounds of the verification tests, U_{ISC} is zero.

If a correction is applied to the pre-verification (following IEC 61400-50-2 Chapter 7) the same correction shall be applied to the post-verification or *in situ* data. If the corrected pre-verification data and identically-corrected post-verification or identically-corrected *in situ* verification are within the uncertainty bounds of the verification tests, U_{PostCal} or U_{ISC} is zero.

If after applying the same adjustment to each, one verification exceeds the uncertainty bounds of the test U_{PostCal} or U_{ISC} is non-zero.

In this case, U_{PostCal} or U_{ISC} is computed:

- Compute the fixed-intercept linear regression slope of the wind speed bin means for the verification test, m_{Cal}
- Compute the fixed-intercept linear regression slope of the wind speed bin means for the -post-verification or *in situ* test, $m_{PostCal}$
- Compute:

$$U_{PostCal} = \left|1 - \frac{m_{Cal}}{m_{PostCal}}\right|$$

If it is not possible to perform a post-verification test on a device due to a device outage near the end of a measurement campaign, or other circumstances, U_{PostCal} or U_{ISC} is non-zero. In this circumstance , an off-site reference data source may be used to assess possible drift in the measurement device calibration. The method for assessing the consistency of the performance of an instrument with respect to accuracy using an off-site reference is as follows:

- Acquire reference data concurrent with the target measurements acquired on site by the primary instrument;
- Bin the on-site data according to circumstances that may influence the relationship between the target measurements and the reference data, for example, to reflect diurnal, seasonal and directional effects by binning according to time of day, time of year, and direction sector;
- Calculate the ratio of the target and reference data in each bin;
- To determine if two periods of time are consistent, perform a Student's t-test on ratios from each period for each bin.

Source	Uncertainty range
Test site	0% to 1%
Onsite sensor	0% [i] to 1%
Offsite reference data	1% to 3%

12.3.1.2.3 Uncertainty calculation

Measurement control	Post verification	Term to use	Other term
Yes	No	$u_{VR,isc}$	$u_{VR,postver}$ should be disregarded
No	Yes	$u_{VR,postver}$	$u_{VR,isc}$ should be disregarded

12.3.1.3 Operational conditions

12.3.1.3.1 Complex flow and complex terrain

The IEC 61400-50-2, Ed. 1 restricts the application of RSD to simple terrain (simple terrain according to Annex B of IEC 61400-50-2, Ed. 10. Background of this restriction is that most RSD's measure different wind speed components in spatially separated probe volumes under the assumption of equal wind conditions across the different probe volumes. This assumption can be violated in non-simple terrain and can lead there to significant measurement errors. Nevertheless, there are different possibilities to control or correct such errors:

- The measurement error due to flow inhomogeneity across the probe volumes can be evaluated with the help of three-dimensional flow models. In addition, IEC 61400-50-2, Ed. 1 includes a simple procedure to estimate this measurement error. Based on such assessments, the position or beam orientation of the RSD can often be chosen such that the respective measurement error remains acceptably low.
- The error assessment by means of the application of three-dimensional flow models can be applied for deriving corrections of the measurement of the RSD.
- There are RSDs with automatic detection of complex flow regimes and internal corrections of the measurement error due to the flow complexity.

Contrary to IEC61400-50-2 Ed. 1, the application of remote sensing is acceptable in non-simple terrain if at least one measurement mast exists on the site. RSDs give additional information about the flow conditions on the site and such can be used as a validation of the flow model, and so reduce modelling uncertainties. See also a more detailed description in Annex IEC61400-50-2 Ed. 1. In this case following conditions shall be considered.

- If no correction of the measurement of the RSD is performed, the respective measurement error due to inhomogeneous airflow as assessed by means of a three-dimensional flow model or by other means shall be calculated and added as standard uncertainty. The total combined uncertainties of the measurement of the RSD must be acceptably low for the required application.
- If a correction of the measurement of the RSD is performed on the basis of a three-dimensional flow model or an internal correction, up to half of the correction shall be applied as an additional standard uncertainty of the correction (weighted with wind rose). For relative wind speed applications (wind shear) the *difference* of the correction at the relevant heights used shall be considered.
- If a three-dimensional flow model is used to assess a correction or to estimate the measurement error due to inhomogeneous airflow, the model shall be applied with a resolution in terms of the wind direction of at least 10°. Furthermore, the spatial resolution of the model shall be appropriate in horizontal and vertical direction such that differences of the airflow covered by the different probe volumes can be evaluated. For usually regarded measurement heights and devices a reasonable mesh resolution would be in the order of 10 m for the horizontal resolution.
- Both uncorrected and corrected wind speed time series must be available to allow the determination of the magnitude of the internal correction and plausibility checks.

Correction methods must be validated and the general correction principle must be transparent.

The symbol for this uncertainty component on a wind speed bin basis is $u_{\mathrm{VR},\,\mathrm{flow},\,i}$.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR},\,\mathrm{flow}}$

Informative recommendation for the calculation of this uncertainty is given in L.4.4 of IEC 61400-50-2 Ed. 1. Alternatively, information for such a calculation can be found in IEA Task 52 reports or CFARS reports.

12.3.1.4 Installation, monitoring and operation of the RSD

IEC 61400-50-2, Ed. 1 and the IEA Recommended Practice 15, further contain requirements on the RSD measurements, which shall be fulfilled and which in the end also influence the accuracy of the measurement. These requirements cover for instance the positioning of the RSD relative to wind turbines and other objects (forests, buildings and sound sources), the parameterization of the RSD, the alignment of the RSD and the synchronization of the RSD with concurrent mast measurements or other measurements.

The calculation uncertainty arising from the document and verification, $u_{\mathrm{VR},\,\mathrm{D},\,i}$, mounting, $u_{\mathrm{VR},\,\mathrm{mount},\,i}$, monitoring during deployment, $u_{\mathrm{VR},\,\mathrm{mon},\,i}$, modification during the measurement campaign, $u_{\mathrm{VR},\,\mathrm{mod},\,\mathrm{I}}$, of the RSD of the device are described below

12.3.1.4.1 Mounting

This uncertainty component covers the uncertainty related to the mounting installation of the remote sensing device. The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR},\,\mathrm{mount}}$

Generally, for profiling remote sensing devices, this tilt-induced error can be modelled by a cosine, modulated by the wind shear. These errors vary slightly for different remote sensors and the device-specific errors should be documented by the device manufacturer.

System tilt shall be logged regularly in RSD metadata.

- In cases where the sensor-specific bias is <0.1% according to the system tilt and the device specific error function $u_{\mathrm{VR},\,\mathrm{mount}}$ shall be zero
- In cases where the sensor-specific bias is ≥0.1% according to the system tilt and the device specific error function $u_{\mathrm{VR},\,\mathrm{mount}}$ shall be equivalent to the bias
- In cases where the sensor-specific bias is ≥0.1% according to the system tilt and the device specific error function, and the bias is corrected, $u_{\mathrm{VR},\,\mathrm{mount}}$ shall be equivalent to the 20% of the bias

12.3.1.4.2 Documentation and monitoring of device health status

This uncertainty component covers the measurement uncertainty arising from the lack of information on the installation of device and the monitoring of the device as well as the impact of erroneous information. This encompasses wrong GPS coordinates, missing reporting of obstacles that can impact the wind flow and any other missing and/or erroneous information that impairs the estimation of the mean wind speed.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR},\,\mathrm{D}}$

The RSD deployment should comply with the RSD manufacturer's recommendations. If the deployment does not comply with these recommendations this should be documented in the service log.

The RSD should be regularly monitored and inspected to detect any problems that could impact the data quality. The monitoring and inspection of the system should be documented with reference to the logs files of the device. Typical health signals are the system logs giving the disk remaining space, the levelling of the system, the internal temperature, the measurement chain operation or the connection to network quality.

The calculation is based on penalties given in case of failure for the below questions. Uncertainty is obtained through direct sum of penalties. In case of failure on all the below questions, a penalty uncertainty of 1.5% could be applied.

QUESTIONS	IF NO THEN PENALTY=
SITE VISIT OR GPS READINGS OF SITE LOCATION INCLINATION/HEADING?	0.25%
REVIEW INSTALLATION AND MAINTENANCE LOGS?	0.25%
SITE VISIT INSPECT/VERIFY THE CONFIGURATIONS?	0.5%
SITE VISIT CHARACTERIZE SURROUNDINGS/EXPOSURE?	0.25%
DOCUMENTATION OF ROUTINE INSPECTION AND MAINTENANCE	0.25%

12.3.1.4.3 Modification during the measurement campaign

This uncertainty component covers the uncertainty related to the modification the remote sensing device during the measurement campaign. It covers the uncertainty due to maintenance and/or repair and/or retrofit and/or upgrade of the system.

The symbol for this average wind speed uncertainty component is u_{VR}, mod

RSD require maintenance to ensure optimal operation and so can require repair and/or retrofit and/or upgrade. Any operation on the device should keep the device operating reliably and in a consistent manner. These operations may involve work on the RSD that could alter the performance of the RSD. The RSD manufacturer must ensure the certification continuity of the measurement.

When an RSD is modified by manufacturer for any of the reasons mentioned, the manufacturer should document all activities that have been carried out. Documentation should include time and date, details of parts replaced or repaired, including serial numbers.

Where calibrated parts are replaced during these operations, the calibration documents should be included, or a proof of the device certification continuity should be given by the manufacturer. All relevant copy of the documentation should be returned to the user. Any modifications that may influence the quality of the data should be highlighted and reported. In case the certification continuity cannot be proven then the device should go through a new verification process.

The same remote sensing device configuration, operating parameters, software, firmware and performance-related hardware components shall be used during the SMC as were used during device classification and during the performance verification test. If not, the manufacturer should demonstrate consistency of measurement before and after modifications.

In case the manufacturer cannot ensure certification continuity or provide relevant documentation, the modification during the measurement campaign is non null. This uncertainty should be evaluated in accordance with the manufacturer guidelines. Values up to 5% may be considered.

12.3.1.5 Adjustment

This is general catch all uncertainty component that applies to any adjustment that has not already being accommodated in this section. It does not include verification 12.3.1.1, classification 12.3.1.0 and complex flow 12.3.1.3.1. This component only applies if an adjustment is performed.

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR},\ \mathrm{ajd}}$

The uncertainty needs to be based upon the adjustment method. The typical uncertainty ranges from 0% to 5%.

12.3.1.6 Data gaps due to low RSD availability

Wind measurements with RSD's can be subject to data gaps of other nature than in the case of the application of measurement masts. These can arise from e.g.:

- Precipitation
- Fog (LIDAR can often not measure in fog)
- Decreasing data availability with measurement height
- Internal data filters
- Atmospheric stability (the availability of SODAR data often decreases at neutral atmosphere due to the lesser or non-existent air temperature gradient)
- Too low aerosol content (can appear at LIDAR measurements, e.g. at clear weather at high altitudes)
- Too high ambient noise or fixed echoes in the case of SODAR measurements
- Outage of power supply

Periods with doubtful measurements must be excluded from the data evaluation. However, care shall be taken if data gaps always tend to appear at similar meteorological conditions and if these conditions are then not well represented in the valid database anymore. In such cases, relations to long-term data can be biased, what can result in significant errors of the long-term adjustments of the measurements.

In case of very low data availability, gaps filling methods should be deployed to augment the dataset. Those methods should be validated and justify additional uncertainty.

12.3.1.7 Data filtering

This uncertainty component covers the uncertainty related to the processing of Lidar data especially with regard to quality check. Device-specific measures should be undertaken according to the advice and guidance of the manufacturers of the remote sensing device employed. For example, the RSD data come with quality indicator that determine quality of measurement. Appropriate filtering should be carried out to ensure good quality of dataset.

This uncertainty component is zero if the data is filtered according to the same scheme than the one used in classification and verification. Limited deviations from the classification and verification filtering scheme can result in acceptable datasets but results in an additional uncertainty component that should be derived using information supplied by the RSD manufacturer.

The symbol for this uncertainty component on a wind speed bin basis is $u_{\mathrm{VR,DF,i}}$

The symbol for this average wind speed uncertainty component is $u_{\mathrm{VR,DF}}$

12.3.2 Combination of uncertainty from bin-wise uncertainty to global uncertainty

The RSD wind speed measurement uncertainty is considered a single value independent of the wind speed, unlike the bin-wise uncertainty described in documents such as IEC 61400-50-2. Therefore, if the uncertainty of wind speed has been calculated on a bin-wise basis, it should be converted into a single value. To do so, the bin-wise uncertainties must be combined as a weighted average, with weights being derived from the wind speed distribution at the site. The wind speed distribution at the site should be derived from measurements made using the RSD. Only measurements considered to be valid should be used to derive the wind speed distribution.

13 Operational Energy Production Data

13.0 Verification of Wind Conditions by Reference Wind Turbine Production Data

In case operational energy production and availability data is available from wind turbines nearby and representative for the planned wind turbine site, this data can be used as main input for an energy yield assessment. These turbines are named reference wind turbines and are used to adjust the meteorology and so represent the site wind conditions. In such a case, model wind data (e.g. ERA-5 or Merra-2 reanalysis or mesoscale data) or wind data from meteorological weather stations, which is deemed suitable for the wind speed and direction distributions, may be used as main meteorological input instead of on-site wind measurements. The used meteorology is verified by modeling the energy yield of the reference wind turbines and scaled until the operational energy yield of the different reference wind turbines is best met.

To apply this OEPR-verification (Operational Energy PRoduction) procedure, the production data must meet specific requirements, which are like those for on-site wind measurements in terms of data period and representativeness.

This section describes these requirements on the used operational data and its treatment, the process of how to verify the used meteorology, and the related uncertainties.

Like wind measurements, production data should span a time period of at least 12 months and be available at least as monthly or daily data. Information on availability and operation mode is indispensable. The use of 10min-Scada data allows a deep analysis and, if needed, more accurate filtering or correction of data. In this way, the most realistic operational energy production can be determined and compared to the modelled energy yield for this turbine. At the same time, uncertainties related to the available production data can be kept low. Therefore, Scada data is to be preferred against data with lower temporal resolution.

Similar to wind measurements, production data have to be long-term correlated. Best practice for the long-term correlation is the derivation of time series of production from reanalysis or other long-term wind data (combining wind speed time series with power curve) and/or the application of production indexes on a monthly basis or at higher temporal resolution. Depending on the calculation approach either the operational data or the wind data must be long-term adjusted.

The flow conditions at the sites of the reference wind turbines, which production data are used to verify the wind conditions, must be representative for the prospective wind turbines. In this context “representative” means the reference turbine and the prospective turbine should have a similar wind regime which has to be demonstrated in terms of the wind speed and wind direction statistics. Therefore, terrain characteristics in terms of orographic complexity, elevation and roughness conditions as well as expected thermal conditions should be similar. Regarding turbine type specifications, the operational reference and prospective planned wind turbines should as well be similar in terms of the power per square meter rotor area and hub height.

High reliability of both the production data and the information on the operation modes of the turbine will decrease uncertainties and will lead to more reliable results of the assessment. The data base should comprise monthly production and availability data as the minimum information. Daily or 10 min SCADA data will reduce the uncertainty.

The determination of the free wind conditions is required for better comparison with wind-based assessments and for a correct assessment of the site suitability parameters. In order to determine the free wind conditions, the operational data must be corrected for loss factors.

Both, time series and statistic (frequency distribution) wind data can be used to create the free wind conditions and the estimation of the energy yield.

In the following paragraphs the requirements are defined, the verification process is described and influencing factors for the uncertainties come in.

13.1 OEPR Verification Process

Long-term correlated production data are used to verify and, if necessary, adjust the modeled wind field, i.e. they are compared to the modeled production of the same wind turbine type with the same hub height at the same site. The application of this verification process includes the following steps:

1. The OEPR data must be corrected regarding availability. The uncertainty decreases with increasing temporal resolution. If no availability is available, an availability of 98% shall be assumed and applied, while uncertainty is increased.

2. The OEPR-data must be long-term adjusted, if not yet covering a long-term relevant period. The methodology for the adjustment depends on the temporal resolution.
3. Losses that apply to the operated wind farms must be added to the measured and long-term adjusted energy yields. An exemption of this rule is the wind farm wakes calculation, which is considered in the modeling part. This results in gaining a gross wind farm production, which is needed to determine the undisturbed wind speeds at the site and to compare gross modeled energy yield with gross operational yield.
4. If SCADA data and metering data at the grid connection point were available, they should be compared to avoid any inconsistency.
5. It is preferred to have operational data of reference wind turbines of several neighboring wind farms. They should represent the area of the planned wind farm in more than one direction. The results of the analyzed wind farms should be combined for comparison of the data and scaled such that a minimum uncertainty results for the calculated energy yield at the wind turbine under consideration. The same applies to the combined use of data from reference wind turbines and wind measurements. Using operational data of a single reference wind turbine or wind farm without further verification opportunities generally leads to an increased uncertainty.
6. The driving wind data for the flow model shall be chosen such that wind distributions are similar to the site of the planned wind turbines.
7. The driving wind data for the flow model shall be scaled such that the gross energy yield of the reference wind farms is met.
8. The energy yield of the planned wind turbines is calculated using the scaled wind data
9. Losses of the planned wind turbines are determined
10. Uncertainties of the planned wind turbines are calculated.

13.2 Requirements on production data from operational wind turbines

1. The reference wind turbines must be sufficiently representative for the wind farm area (defined here as the area covered by the planned wind turbines). The suitability of the reference wind turbines is site-specific and is determined by the wind flow complexity (roughness, in particular forests, orography, elevation and thermal conditions) and their distance to the regarded site. It must be assured that the adopted flow model is appropriate for the site under consideration.
2. The static data of the reference wind turbines is required. It includes geographic coordinates, turbine type, hub height and neighboring wind turbines.
3. Production data should be available with time period of at least 12 months covering all seasonal variations of a year. 12 consecutive months with high availability are preferred because that might lead to lower uncertainties.
4. The data must be available for every single turbine.
5. The data must have monthly resolution or higher.
6. the following information should be available for analyzing:
7. Operational mode (e.g. noise reduced mode during nights)
8. Temporal availability
9. All loss causing regulation (bat restrictions, shadow, sector management, grid limitation etc.)
10. Any change in the layout of the analyzed wind farm (new turbine, forestry cutting, etc.) during analyzed period, including the exact time of the change.
11. Power curve and ct-values. Using a power curve that has been measured in the windfarm is preferred for the energy calculations.
12. If the simulation of the wind potential and the estimation of the energy yield were based on time series, the operational production data should comprise hourly data on production and availability as the minimum information.

13.3 Uncertainty of the OEPR Verification Process

This section is defining the process of assessing the uncertainty of operational data. This assessment replaces one of the site measurement data uncertainties within the combined uncertainty assessment.
Assessing the uncertainty of verification process comprises the consideration of several sub-categories which are listed and described below:

- **Production data quality and integrity**

Production data may have different sources from high resolution SCADA data including status log information to data bases with monthly yield data and availability. The overall uncertainty of the data adopted for the verification process shall take the following sub-components into account:

  - Availability and quality of Operational Reports
  - Availability and quality of SCADA documentation
  - Energy production assignable to individual wind turbine
  - Data Quality
    - Detection and elimination of erroneous data
    - Temporal resolution (monthly, daily, hourly, 10 or 15 minutes)
    - Temporal or energetic availability
    - Length of data period
    - Point of measurement (wind turbine / Grid connection point)
    - Class of Uncertainty of the metering equipment
    - Correction concerning availability
  - Reliability of information
  - Detail of information (restrictions, varying operation modes, availability of information on neighboring turbines ...)
  - Review of all losses and connected uncertainties according to section plant performance

- **Wind data (wind direction and k)**

Uncertainty of wind direction distribution and k-factor must be assessed. This should be done using the data of the reference wind turbines with high temporal resolution or of a wind measurement in the surrounding of approx. 50 km in comparable terrain can be used. If such a validation is not possible an uncertainty of … should be applied for the wind data uncertainty.

- **Operation mode and Losses**

Information on the operation mode is of importance to properly perform the verification process and to account for losses of the reference turbines. More detailed description can be found in the section of Plant Performance. The uncertainty of the operation mode component comprises the following sub-components:

  - Turbine interaction
  - Availability
  - Electrical Efficiency
  - Environmental losses
  - Curtailments

- **Turbine performance**

When in operation, wind turbines may show a different performance from the one which would be measured under standard test conditions. More detailed description can be found in the section of Plant Performance. To evaluate the uncertainty related to turbine performance the following must be considered:

  - Sub-optimal wind farm performance
  - Generic power curve adjustment
  - site specific power curve adjustment
  - hysteresis (high wind, …)

- **Representativeness of reference wind turbine for planned wind turbine**

The reference turbine(s) has (have) to be representative for the planned wind turbines (see above for explanation of representativeness). The difference in hub height between the reference wind turbine and the prospected turbine directly also influences the uncertainty. The uncertainty components are

  - wind turbine type (rated power, rotor diameter, technology)
  - Reference wind farm array (Wakes and Blocking, informative)
  - Vertical extrapolation in each reference wind farm
  - Horizontal extrapolation in each reference wind farm

- **Long-term Adjustment**

The long-term adjustment comprises uncertainty components similar to those for the long-term adjustment of wind measurements except that here the long-term data source consists of time series of power production. In case a production index is applied for the long-term correlation the uncertainty of this index has to be accounted for.

The quantification of uncertainty if long term adjustment is described in the section of Historical Data.

14 Vertical Extrapolation Uncertainty

The present methodology to calculate vertical extrapolation uncertainty is limited to:
Vertical extrapolation of wind speed (e.g., mean wind speed, Weibull-scale parameter, or reference wind speed) from one height to another. Vertical extrapolation of distribution shape (e.g., Weibull-*k*), wind direction, and turbulence intensity are not considered here.
The methodology assumes independence of vertical extrapolation uncertainty from other uncertainties, i.e. no correlation with horizontal extrapolation, long-term corrections, etc. It is also assumed that vertical extrapolation uncertainty is random and normally distributed (Gaussian), allowing combination with other uncertainties and consistent with the Central Limit Theorem. It is recommended to use the appropriate measurement levels that represent the desired calculated variables (hub height wind speed, equivalent rotor wind speed or shear profile across the rotor)[4]. Heights are specified as height above ground level over land; over water, the height definition should be specified, e.g. above mean sea level (MSL).
For the following three methods of vertical extrapolation, the vertical extrapolation uncertainty can be accounted for as described in XX:

1. application of power law profile modelling;
2. application of profile-based and/or linearized wind flow modelling including surface roughness;
3. application of RANS (Reynolds-Averaged Navier Stokes) solvers for wind flow modelling.

14.0 Power law profile modelling

The mean wind shear exponent (α), defined through the power law wind profile[5]

$$V(z) = V(z_r) \cdot \left[\frac{z}{z_r}\right]^{\alpha} \tag{14-1}$$

where

V is the mean wind speed, expressed in meters per second [m/s].

z is the predicted height, expressed in meters [m].

z_r is the reference height, expressed in meters [m].

α is the shear exponent that governs the rate of change of mean wind speed over height, expressed as unitless parameter

The shear exponent can be related most directly as

$$\alpha = \frac{dV/dz}{V/z} \tag{14-2}$$

We specify use of a *mean* α to vertically extrapolate *mean* wind speed *V*, allowing for frequency-weighted means. We begin by assuming measurements covering an integer number of years, with later modification allowable for using monthly means or diurnal/hourly groupings.

Starting for the simplest case of two measurement heights (z_1, z_2), the centered, theoretically ‘exact’ formulation (2) is compatible with the commonly used practical form of calculation,

$$\alpha = \frac{\ln[V(z_2)/V(z_1)]}{\ln(z_2/z_1)} \tag{14-3}$$

Wind shear exponents are assumed to be calculated via (3), using wind speeds averaged over a fixed time interval (standard is 10 minutes; but it can range anywhere from 1 minute up to 30-minutes). These

[4] Data from measurement levels at a significant distance from the hub or rotor height(s) may lack significance for the purpose of this standard, and may subsequently be discarded; in such cases, the reasons for selection of measurement levels shall be stated by the user.

[5] The shear exponent here is meant for vertical extrapolation, distinct from that used for site suitability and loads calculations.