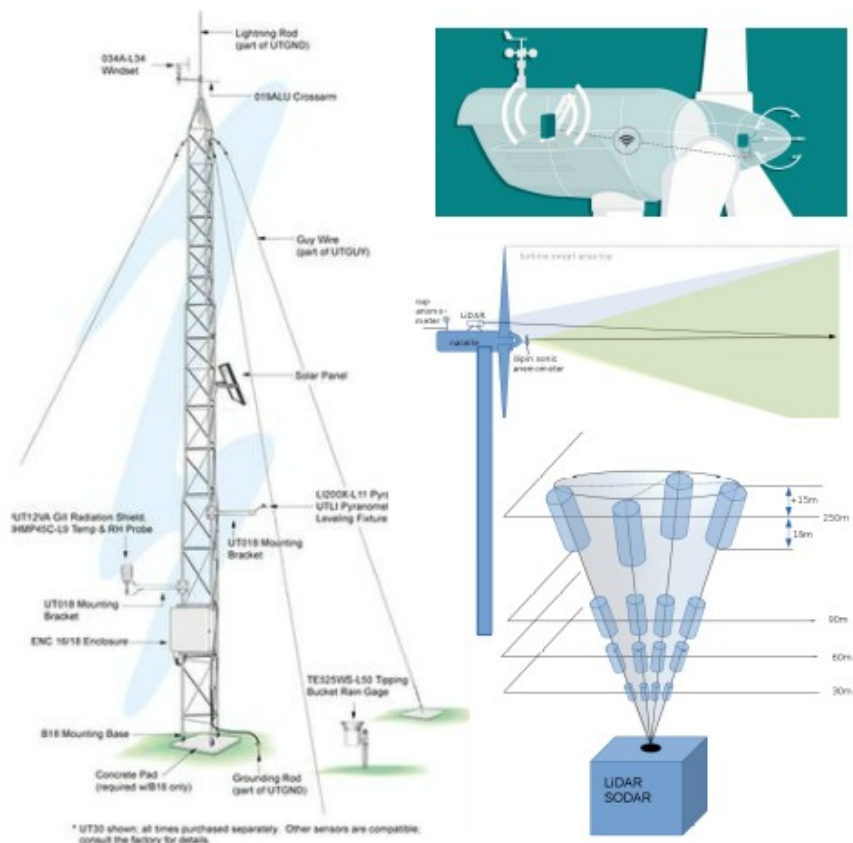


EIRGRID Met Mast and Alternatives Study

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Final Report



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December 2019



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1. Background of the Study

1.1 Introduction

The current grid code enforces wind farms to deliver meteorological data to EirGrid and SONI. Wind farms greater than 10 MW in size are required to submit four meteorological data signals:

- Wind speed
- Wind direction
- Air pressure
- Air temperature

This data is collected within EirGrid and SONI and thereafter used in the wind power forecast process. Especially for the detection of high-speed shut down events, the wind speed signal is the most important of these variables. A real-time forecast process must apply quality control to only use data that reflects the reality of the current weather conditions at the wind farms. In the case of poorly maintained data recording and delivery, the forecast process will reject a large fraction of data leading to higher errors in the wind power forecast. Inaccurate wind forecasts can lead to incorrect actions taken by the System Operator control room engineers. Similarly, the control room engineers could also ignore warnings on the basis of wind forecasts due to mistrust, which could lead to critical situations.

High-Speed Shutdown events

During storm events, it takes less than one hour from when the wind speeds pick up at the west coast of Ireland until a major proportion of the wind farms could be covered by a High Speed Shutdown (HSSD). This poses a risk during storm events and results in the System Operator having to limit the wind generation in advance so that sufficient reserve is available. In some cases wind farms not impacted by the HSSD event need also to be limited due to the uncertainty of the event in time and space. These wind farms are then available to provide reserve when the events take place.

Need for accurate met data signals

The short time interval in critical weather events calls for wind farms to provide reliable weather information. To verify that the meteorological signals are valid they are needed not only in extreme weather.

The quality of the daily data needs to be continuously monitored in order to provide confidence when making decisions. Despite that the systems are automated and intelligent, this reliability of the weather information is essential and this importance increases with growing wind penetration. Ireland is geographically the first country in Europe to experience storms propagating from west to east. The information on the storm track and intensity of low pressure systems is sparse to the west. Therefore, weather forecast uncertainty is higher and the growth rate of the uncertainty is often high during storm events. For this reason, growing wind power capacity on the island needs to be accompanied by increased reliability of the wind power handling, which is a combination of wind power forecasting and real-time decision making in the control room.

1.2 Investigation Process on Grid Code Requirements

EirGrid started an investigative process in 2016 on the grid code requirements for the provision of wind speeds from meteorological masts. The question posed was whether the requirements should be modified to allow for alternative technology sources to meteorological masts.

WEPROG was contracted for the study and concluded from the available data that the investigated alternative technologies could not fulfill the accuracy and reliability needed in the forecasting process. After this first study was carried out, it was found that the information with respect to the source of wind data that was delivered to EirGrid was inaccurate. Some wind farms had switched from mast to nacelle instrumentation and data delivery without notifying EirGrid. Therefore, the conclusions of the first study's results regarding the value of mast versus nacelle data was not correct.

Workshop on results from part 1 of the study

Following a workshop it was agreed that the study had to be renewed with more wind farms and also including wind farms from Northern Ireland. An additional scope for the new study was to develop some objective criteria for the quality of meteorological data given that the first study revealed significant differences between wind farms.

Northern Ireland and the Republic of Ireland have different grid code requirements on the source of meteorological data. Therefore, nacelle data may have gradually spread out over Ireland. The analysis of the data showed that changes in instrumentation lead to changes in the statistical characteristics of the measurement data.

Questionnaire on the source of meteorological data signal

In 2017 EirGrid launched a questionnaire to all wind farms on the source of meteorological data signal in order to clarify the data source and the calibration history of currently delivered met data. Following the questionnaire EirGrid was finally able to provide input and information for the second study.

This second study was expanded to 93 wind farms over a four year period. The results then explained both why the first study turned out negative on measurement data from nacelle sources and why there are significant differences in the quality of the data.

1.3 Requirements in other jurisdictions

A number of system operators have been selected for the purpose of comparing the requirements regarding the integration of wind energy into the electrical grid. It can not be considered a market review, because we limited the comparison to six system operators in North America and one in Europe, as their requirements are most comparable to the Irish requirements and the control areas are most similar to the Irish terrain and wind regime.

Even though there is some externally managed meteorological site data available, the control areas of Denmark and Germany are not taken into consideration, because collection of met data is not a grid code requirement and the wind fleets are organised very differently than in Ireland. In these areas, wind energy is dispersed in small units of often only 2 – 3 wind turbines over large areas, which is not comparable to the Irish grid. Most other European transmission system operators are not very focused on meteorological data acquisition in conjunction with wind energy integration and many have also not updated their grid code yet or the grid code is only available in their native language.

The selected system operators and their respective technical requirements were:

- **AESO:** Alberta Electric System Operator in Calgary, Alberta, Canada [AESO,2011]
- **CAISO:** California Independent System Operator [CAISO, 2014, 2016]
- **BPA:** Bonneville Power Administration in Portland, Oregon, USA [BPA, 2015]
- **ERCOT:** Electricity Council of Texas in Austin, Texas, USA [ERCOT, 2012]
- **NYISO:** New York Independent System Operator in Rensselaer,NY,USA [NYISO, 2016]
- **PJM:** Independent System Operator in Audubon, PA, USA [PJM, 2016]
- **HECO:** Hawaiian Electric Company, Maoui, Hawaii [HECO, 2016]
- **LitGrid:** in Vilnius, Lithuania [LiTGRID, 2010]

Data Requirements of other system operators

It can be stated that all of the above system operators that require meteorological data delivery use a similar formulation in their technical requirement guides. The requirements in all cases have a time frequency of delivery under one hour (between 2s in the PJM control area and 15 min in the Hawaiian control area of HECO) and a threshold name plate capacity of 1–30 MW, above which delivery of meteorological data is a must.

The variables to be collected are in all cases wind speed and direction at hub height or nacelle, temperature and pressure (except for LitGrid). In some cases humidity and air dew point temperature at 2m height are required for half of the TSOs. In one case (AESO) an ice-up signal is required to be sent.

Two of the SOs require standing geodata from every wind turbine (CAISO, BPA) and one also requires wind farm layout information (NYISO). This has to do with that NYISO encourages in their latest update from June 2016 the wind plant operators to collect and send data "...from as many points at the Wind Plant as are available. Ideally, the minimum amount of data would be provided from a stand-alone meteorological tower(s) and augmented with additional sensor data from the turbines." [NYISO, 2016]. This may have to do with the fact that NYISO allows data to be collected from a turbine mounted equipment, if no stand-alone tower exists. However, it is a requirement to get approval, if any measurement unit is exchanged or decommissioned.

All system operators except LitGrid ask for wind measurements from a met mast at hub height or equivalent instrumentation. In the LitGrid control area, wind farms have to deliver wind speed, wind direction and temperature from at least two corners of the wind farm to ensure that measurements are not contaminated by wake effects.

The benefit of this strategy is increased amounts of measurement sources and significant lower costs for the wind farms. The drawbacks of nacelle wind measurements are the uncertainty regarding yaw misalignment and corresponding wake effects. The following Table 1 provides an overview of the requirements of the eight selected system operators for comparison.

What is common across all system operators is that the frequency of delivery is relatively high, also for meteorological data. This is mostly due to the differences in market structure, especially where VERs (Variable Energy Resources) are also traded in short-term markets, but also, because wind speed measurements are more and more used for dispatch and to shorten curtailment times.

System Operator	Standing Data				Equipment				Met variables to be delivered						
	threshold [MW]	frequency [sec]	geodata per wind farm	geodata per turbine	met mast	nacelle	other	ws	wd	T2m	PS	DP	HUM	other	location agl.
AESO	5	60	1	0	1	0	0	1	1	1	1	1	1	iceup	hub/2m
CAISO	1/5	4	1	1	1-2	1	0.5	1	1	1	1	0	0	0	hub(+10m)/2m
BPA	20	60	1	1	1	1	1	1	1	1	1	0	1	0	hub/2m
ERCOT	1	300	1	0	1	0	0	1	1	1	1	0	0	0	hub/2m
NYISO	1	30	1	0	1	0.5	0.5	1	1	1	1	1	1	0	hub/2m
PJM	10/100	10/2	1	0	1	0	0	1	1	1	1	0	0.5	0	hub/2m
HECO	all	900	1	0	1	0	1	1	1	1	1	0	0	0	hub+windNET
LITG	20	300	1	0	0	2	0	1	1	1	0	0	0	0	nacelle

Table 1.1: Summary of technical requirements in other control areas/jurisdictions. Abbreviations for the variables are ws=wind speed, wd=wind direction, T2m=temperature at 2m, ps=surface pressure, dp=dew point temperature, hum=humidity, frequency=deliver frequency, threshold= threshold nameplate capacity of the wind farm, where the rules are applicable.

Situational Awareness in the control room

To our knowledge, there are so far three transmission system operators that have dedicated situational awareness through meteorological information on their priority list or have an application in operation:

1. **HECO:** the Hawaiian system operator has setup a wind NET network of LiDARs and SODARs at prevailing storm tracks and make these measurements visible together with ensemble forecasts [Nakafuji, 2016]. In that way, the operators get more confidence in the forecasts and are better to allocate the required reserves, especially in critical events.
2. **ERCOT:** the system operator of Texas, USA, has implemented a “Renewables-focused Operations Desk” in spring 2017 to mitigate reliability challenges due to increased generation from wind farms.
3. **50Hertz Transmission:** the TSO of the eastern part of Germany has setup a GIS-based system with layers of different meteorological information that can be displayed in the control room on top of the grid (see figure 1.1). This is relevant for temperature line rating, but also for extreme wind speeds at critical grid points, where a lot of wind feeds into the grid. They are working with so called “actuals” that are either wind measurements or short-term forecasts in addition to long-term forecasts for the next 7 days. In that way, the control room and analyst group can perform long-term as well as short-term planning of reserves helping them to prepared for extreme events.

Ideally, both meteorological forecasts and power forecasts should be integrated with uncertainties to enhance the situational awareness regarding extreme events as done in HECO. Nevertheless, both examples show that it has become a necessity in the control room of the TSOs to gain not only an overview of the power feed-in, but also the weather situation at hand and in the near to medium term future. The next step would then be to load the layers of the extremes (low/min and high/max) from ensemble forecasts that can display possible minima and maxima on horizontal plots (see Figure 1). With the worldwide highest penetration level of 47%, 50Hertz is maybe a pioneer on this. With higher penetration levels, curtailment and feed-in restrictions during ramping phases as well as shorter dispatch times will become unavoidable. The efficient balancing of wind power will with increasing penetration level therefore also require forecasts with higher time frequency updates. Since meteorological update will stay in the 6-hourly schedule, updates with point data will be required to make forecast updates on minute basis. This is already possible today with updates on a minute basis, for example with algorithms like WEPROG’s inverted Ensemble Kalman Filter (iEnKF), where point data of any kind related to the wind power is assimilated into a portfolio forecast of an area [Möhrlen et al. 2009]. Increased availability of high quality power production and wind measurement data is however a prerequisite for the updates to be of higher quality than persistence.

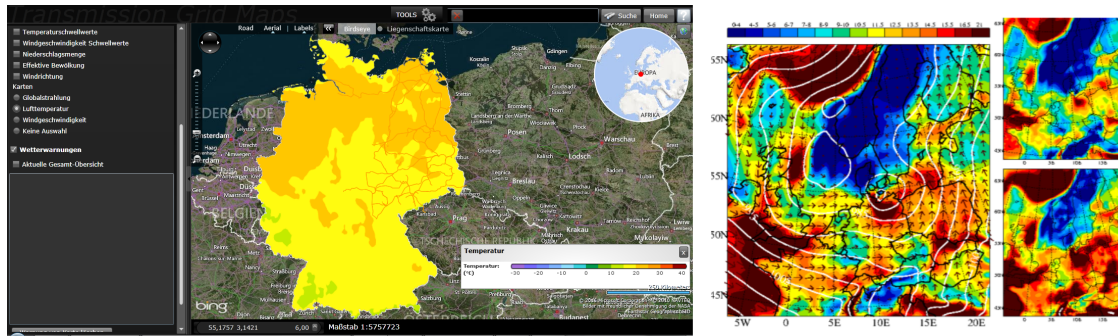


Figure 1.1: Example of the control room GIS display with layered temperature graphics at the German TSO 50Hertz Transmission (left image: courtesy of 50Hertz, with kind permission) and possible layouts in large scale or local scale including minimum and maximum (right figure with mean (large figure), min (upper fig.) and max (lower fig.) wind speed at 100m agl. and isobars centred over Germany).

1.4 Definition of nacelle wind speed

The only information that was available in this study regarding the computation of individual nacelle wind speed data signals was from personal communication with some wind turbine manufacturers and researchers. It can be seen from the results that the processes are different and they require calibration. When we refer to a "nacelle wind speed" in this report, this is defined as wind speed data measured from means other than that mounted on a meteorological mast. The wind speed data could be recorded by cup-anemometers on one or more wind turbines. Alternatively, the wind speed can be a computed result of pressure generated torque on the wind turbine blades taking the pitch angle into account. Both signals are sensitive to circumstances and conditions on the wind turbine, the wind farm and the software provided by the manufacturer.

Characteristics of Cup Anemometers

The cup-anemometers are sheltered by the wind turbine itself and affected by turbulence around the blades. Over-speeding of cup-anemometers as well as wake effects from downstream wind turbines due to such turbulence are reported and they are dependent on the wind direction. These are the core reasons why the nacelle wind speed have not been considered acceptable in accuracy nor in terms of providing an independent measurement signal in general. Given these potential issues, it was expected for this study that there could be differences in data quality from these sources caused by differences in turbine manufacture data handling, wind farm size, wind turbine model, the age of the wind turbine and other characteristics of the individual wind farms both with respect to physical conditions and installed software. Therefore, all wind farms on the island had to be included to test the quality of the data.

Hornsrev Study

A study on a single wind turbine on the Hornsrev 2 offshore wind farm (referred from here on as the *Hornsrev study*) on the Danish west coast has shown that there are different wind speeds available [Gömen, 2018] and [Göen, 2016] on modern wind turbines. There is the raw nacelle cup anemometer and a manufacturer computed wind speed. The different wind speeds were then also compared to wind speeds from a met mast. The authors tried to simulate the computed wind speed from the manufacturer software with a good fit. The *Hornsrev study* describes this process of computing the manufacturer wind speed as confidential. From the results it can be derived that the manufacturer uses the pressure on the blades to compute the wind speed signal.

There is no HSSD presented in the data of the *Hornsrev study*. However, it is likely that wind speeds during complete HSSD would be based on the nacelle cup-anemometer due to the missing torque from the rotation of the blades.

When calculating the wind speed based on the flow through the rotor area, the power curve fits the wind speed and power generation almost perfectly and is superior to the cup anemometer fit. While this is perfectly acceptable in normal conditions, the signal will differ in their characteristics during HSSD, or when the wind farm is limited in its generating power. Therefore, it could be expected that a training algorithm targeted to predict HSSD from the wind speeds cannot always provide reliable forecasts. A shift in the statistical characteristics at the HSSD point will add noise to the calibration. This is unwanted, but on the other hand the result from the Hornsrev2 wind turbine in the *Hornsrev study* indicates that the lower range wind speeds are very accurate. The blade pressure based wind speed is an accurate approach, but there is a pitfall above the HSSD point, where the rotor does not generate torque and the cup anemometer is the only option to create a wind speed signal. In this case, a shadowing of the cup-anemometer is a risk factor, which can generate additional uncertainty. The wind farm manufacturer will likely generate a continuous wind speed around the HSSD point, but workarounds are required to circumvent impact of turbulence and pitch angles. The most optimistic outcome will be a continuous transition from strong pitching to HSSD such that the cup-anemometer wind speed increases in a manner, which reflects the true wind speed changes even though some bias from the shadow is inevitable.

Ageing of wind turbines

Another potential issue of the blade pressure based wind speed is that load on the blades over time will cause the blades to get softer. The wind turbine will despite softer blades still reach the rated capacity, but at a slightly higher wind speed. A backward calculation from blade pressure will therefore require re-calibration as the blade softens with age. The wind farm aggregated blade pressure wind speed will also be influenced by unavailability of wind turbines. This is most critical in complex terrain, where there are greatest differences in wind speed across the wind farm.

Challenges with manufacturer controlled wind speed measurements

It is essential to maintain control over how wind speeds are calculated by wind farms, if manufacturer controlled wind speeds are accepted as a valid source of wind speeds. Notification of changes to EirGrid and SONI is required. The uncertainty in the calibration increases, when the wind farm owner does not have a service and maintenance contract in place with the manufacturer, but with an independent third party. There are also risks in that manufacturers may have other interests in the nacelle wind speed than what is optimal for system security. The manufacturer interest is to ensure that their customers can verify that the wind farm delivers the expected power given the available wind speed. This will be the primary focus for the two parties.

An accuracy requirement during rare peak wind speeds around HSSD is not expected to be commercial focus area, unless it is monitored to a specific requirement. Therefore, we must expect that the quality of the wind speed signals for wind turbine manufacture lies in the most frequently occurring wind speed range. Their interest at the high wind speed range is mainly to protect the wind turbine itself to prevent fatigue, material breakages and reduce maintenance costs.

The questionnaire from EirGrid on the wind speed source was replied sparsely. There were a moderate number of answers and the replies were partial. The questionnaire does not provide a strong indication of whether wind farm owners have knowledge of how their nacelle wind speeds are calculated. This can become a limiting factor for how the data can be used, as it poses uncertainty on the quality of the data as well as the quality assessment methodologies to be used to ensure high-quality data.

1.5 Instrumentation

Meteorological measurements provide an independent measure of the wind resource and weather situation at any given time. This information can and is, as technology enhances, not only an obligation that stems from technical requirements of the system operator, but is also used to optimise the operation of wind turbines by the wind farm operators. For both the system operator and the wind farm operator, these measurements are an independent signal at the wind farm that can warn about critical weather and provide an indication on whether the wind turbines work at their expected performance level. For the transmission system operator, such measurements can additionally be used for situational awareness of the weather in the control area that may affect the transmission lines. They also provide a second means of verification, whether the power signal at a given wind farm is malfunctioning in situations that may be critical in terms of grid operation. In recent years data assimilation with independent measurements from wind farms are also being tested by meteorological centres (e.g. Marquis et al. 2012, EWeLINE, 2011). One of the most important findings so far is that the quality of data provided is the most essential issue to be solved in order to gain higher quality forecasts with such measurements. In fact, it has been identified that if there is no specific effort put into standardisation of requirements in the power industry, the benefits can not be achieved. A work package in the newly started IEA (international energy agency) Wind Task 36 Wind Power Forecasting [IEA, 2016] has been created in order to provide recommendations for standards regarding measurement quality control. In the following, we will therefore list the available instrumentation, discuss how measurements are recommended to be setup and which implications the use of the various instruments have on data quality and usability in the operational context. Typical instrumentation for meteorological measurement campaigns in the wind power context are divided into two categories:

- meteorological masts
- remote sensing instruments

The typical instrumentation on meteorological masts are:

- cup anemometers
- sonic anemometers
- temperature sensors
- pressure sensors
- hygrometer sensors
- precipitation sensors/ rain gauges

The remote sensing instrumentation are:

- Wind Profiling Radar
- SODAR
- LiDAR
 - Wind Profiling LiDAR
 - Scanning LiDAR (Long-Range and short-range wind tracer)

Not so common instrumentation or additional instrumentation are:

- Microwave Radiometers (measures energy emitted at sub-millimetre-to-centimetre wavelengths at frequencies of 1–1000GHz)
- Ceilometer (light source to determine the height of a cloud base. Ceilometers can also be used to measure the aerosol)
- Microbarographs (measures atmospheric pressure)

In the following, we will concentrate on the wind speed instrumentation of met masts and remote sensing. All other instruments are mostly used in research measurement campaigns and in meteorological projects. Literature on other types such as microwave radiometers are described by e.g. Ulaby [1982] and Matzler [2006], for ceilometers by Morris [2016], or microbarographs by Monserrat [1992].

1.5.1 Meteorological masts

Meteorological masts are still the most commonly used measurement instrumentation for the planning phase and operation of wind farms. An example is shown in Figure 2.

Typically, these met masts have the following instrumentation attached:

- wind vanes
- cup and/or (ultra) sonic anemometers
- temperature sensors
- pressure sensors
- humidity sensors and rain gauges

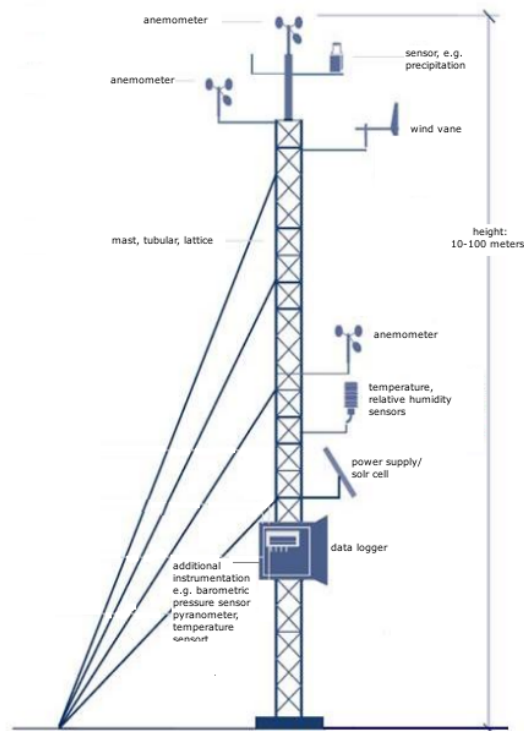


Figure 1.2: Example of a typical met mast with various instrumentation, data logger, power supply and wiring. Typical instrumentation are cup anemometers or sonic anemometers, wind vanes, temperature, pressure and air density sensors, pyranometers and precipitation and humidity sensors.

For resource or site assessment in the planning phase of a wind farm an IEC standard exists [IEC, 2005] with an updated version 2 (IEC 61400-12-2:2013), that specifies which tests and what kind of criteria the instrumentation has to fulfil when used for the required tests to be carried out. The IEC 61400-12-2:2013 rules contain the following items:

- Extreme winds
- Shear of vertical wind profile
- Flow inclination
- Background turbulence
- Wake turbulence
- Wind-speed distribution

The results of these tests have to be within a pre-defined range to be acceptable. In Appendix F of the 61400-12-1:2005 "Cup anemometer calibration procedure" the calibration of the instruments for measuring wind are specified.

MEASNET (MEASuring NETwork), the "international network for harmonised and recognized measurements in wind energy" has defined so called "Round Robin rules" for calibration of cup anemometers for wind energy [MEASNET, 2009], which are widely used. MEASNET has also under the EU project ACCUWIND published a number of guidelines regarding instrument calibration and measurement campaigns for the wind industry (Dahlberg et al., 2006, Pedersen et al. 2006, Eecen, 2006). Lee [2008] found a way of calibrating wind direction sensors with an optical camera.

The Annex D in IEC 61400-12-1:2005 standard states that the "implicit assumption of the method of this standard is that the 10 min mean power yield from a wind turbine is fully explained by the simultaneous 10 min mean wind speed measured at hub height, and the air density" [IEC, 2005, Annex D, Table D.1] and describes the associated measurement uncertainty evaluation principles. In this respect, the standard refers to the "ISO Guide to the expression of Uncertainty in Measurements" [JCGM, 2008, 2009] and its 2 supplements [JCGM, 2008a, 2011] from the Joint Committee for Guides in Meteorology (JCGM), where there are two types of measurement uncertainty that are to be accounted for in any standardised measurement taking:

1. (1) systematic errors, which are also known as measurement bias, often associated with offsets of the measured quantity
2. random errors, which are associated with the fact that 2 measurements of the same quantity are seldom the same

In section 3.1.2 of the guide, [JCGM, 2008a, 2011] it is stated that "the result of a measurement .. is only an approximation or estimate .. of the value of the measurand and thus is complete only when accompanied by a statement of the uncertainty ... of that estimate". Considering this definition, all measurements should ideally have an uncertainty term associated with it. This is impractical in real-time operations, where the value of the measurements lies in the availability of the data at a given time. Therefore, it is unrealistic to request uncertainty measures. However, it could be a standing data value that is determined at the setup of the instrument and provided as part of the standing data. In that way, the instrument specific uncertainty could be accounted for in the handling of measurements.

The alternative is to carry out an uncertainty estimation with e.g. the Monte-Carlo method described in [JCGM, 2011 pp23-33] or a mean uncertainty value must be added to raw measurements, as applied by Pinson and Hagedorn in an experiment over Ireland and Denmark with wind measurements from standard met masts [Pinson and Hagedorn, 2012 p7]. If a more standardised technical requirement is desirable, the JCGM guides offer a valuable general source, also applied in meteorology and oceanography. In that way, a harmonisation of "best practices" with these directly related real-time disciplines can be achieved. In fact, the guides do not only consider the measurand as a physical quantity, but also provide guidance to the conceptual design and the theoretical analysis of measurements and methods.

In the introduction to the Guide [JCGM, 2009], it is stated that "...the principles of this Guide are intended to be applicable to a broad spectrum of measurements", including those required for:

- maintaining quality control and quality assurance in production
- complying with and enforcing laws and regulations
- calibrating standards and instruments and performing tests throughout a national
- measurement system in order to achieve tractability to national standards developing, maintaining, and comparing international and national physical reference standards, including reference materials

To summarise, the handling and integration of wind power into the electric grid is an equally important step to harness the full potential of the energy resource in an efficient and environmentally friendly way.

This requires that measurements are trustworthy and maintained to a quality that allows for their use in forecasting tools in order to produce high quality forecasts and thereby reduce the need of reserves. These guides in combination with the IEC 61400-1 standard would provide a good foundation for any grid code technical requirement specifications.

1.5.2 Remote Sensing devices

Remote sensing has a long tradition in geology, atmospheric science, hydrology and oceanography and other earth sciences. The earliest remote sensing "devices" were aerial photography that was analysed with the heights and the geographical space in which the pictures were taken. Today remote sensing can be described as an aerial sensor technology, in which objects are detected and classified by means of propagating signals that are analysed according to computations that relate the object of interest to the observation. Wikipedia [2016] describes modern remote sensing as an inverse problem, in analogy with the determination of the type of animal from its footprints. This means that the main principle of remote sensing is not the target itself being measurand, but instead an object is measured, directly or indirectly, that contains a well defined relationship to the target. The desired value is then computed from the taken measurement.

There are two types of modern remote sensing devices:

1. active sensors
2. passive sensors

The active remote sensors work with signals, mostly radiation that are directly measured at or towards the objects. Instruments include e.g. photography, radiometers, infrared devices. Passive remote sensing works vice versa, i.e. the sensors emit energy or sound to the objects and measure the radiation that is reflected or back-scattered from that object (see Figure 1.4). Examples of such devices are RADARS (Radio detection and ranging Sensor), SODARS (SOund Detection and Ranging Sensor) and LiDAR (Light Detection and Ranging Sensor) and Satellite-based sensors. The quality of remote sensing data is very much dependent on its spatial, spectral, radiometric and temporal resolutions.

A comprehensive literature review on Remote sensing for Wind Energy has been compiled by DTU Wind Energy Department after a summer school on the topic. It described the most commonly used instruments and their applicability for wind energy applications [Pena, 2013]. The following descriptions and discussions are based to a large degree on information from this compendium. Additionally, a number of commercially available remote sensing devices have been analysed for the purpose of real-time wind measurement and associated parameters as alternative to met masts. Remote sensing in wind energy is mostly driven by a desire to find alternative measurements for expensive and at times difficult installation and erection of met masts. Especially with increasing hub heights, met mast heights have grown to a size, where the erection requires planning permission and cranes of significant size. Hence, it has become so expensive that previously never considered alternatives from the remote sensing area have become price competitive.

The main driver of recent developments has been the competitiveness in price, the ease of installation and the increasing heights of wind turbines and size of the projects, where it is often no longer sufficient to measure at only one site. Nevertheless, the disadvantage of not directly measuring the target value is still present [Würth et al., 2018]. With increasing experience and technical advances in computational science and technology, the remote sensing devices have however become a real alternative.

This has also been reflected in the IEC 61400-12:2005 standard, where remote sensing devices have been incorporated as possible devices to carry out wind measurements for wind energy applications in the 2017 update (IEC 61400-12:2017).

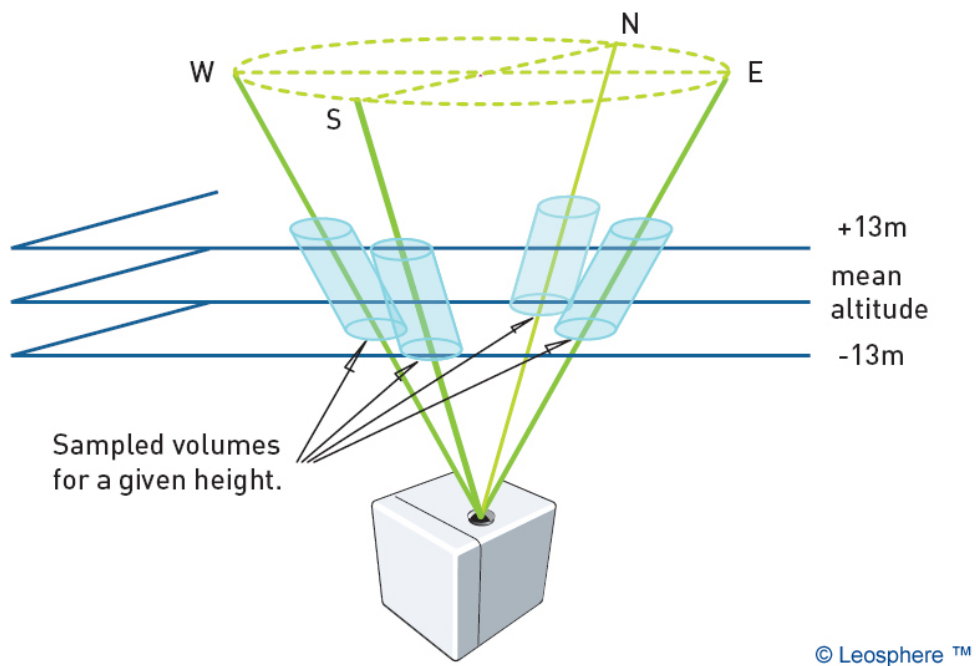


Figure 1.3: Principle of the remote sensing devices' scanning. Picture shows a Windcube from Leosphere.



Figure 1.4: Examples of LiDARs for wind energy applications. Gallion (left top), Leosphere Windcube (right top), ZephIR (left bottom), Wind Tracer, Doppler LiDAR Lockheed Martin (right bottom).

Looking at the benefits outlined by manufacturers of remote sensing devices (e.g. Sgurr Energy, Vaisala, R-NRG) the following list of key advantages of using remote sensing devices in wind energy applications can be summarised to:

- Minimal environmental impact
- Short installation time
- Highly portable
- Short lead times
- Wind profiling, also above mast height
- Measurements over an area or volume

The main technical advantage to be considered is the ability to measure over an area or volume rather than at pre-defined fixed heights above the ground. This is also how forecasting models work. NWP models compute variables across grid cells as area averages and area verification of variables are widely applied for model verification in meteorology.

The drawbacks of remote sensing devices so far have been the high costs of LiDAR and for both SODAR and LiDAR inaccuracies of signals in complex terrain. According to the white paper of the Deutsche Windguard [2013] and Bradley [2008], especially "in complex terrain sites, influence of the relatively large scanning volume of today's LiDAR and SODAR must be carefully considered in terms of its influence on the measurement accuracy..". This has been a general observation and a large research topic [see e.g. Bradley, 2012a, Bradley, 2012b, Emeis et al, 2007, Kindler, 2007, Yang, 2013].

Although LiDARs and SODARS, as well as RADARS and wind profilers have quite a long tradition to be used in measuring campaigns in atmospheric science, data assimilation and numerical modelling (e.g. [Wilczak et al, 1995, Grund et al., 2001, Benjamin et al., 2004, Pichugina et al, 2008]), these instruments have been prone to measurement uncertainty and require special treatment and verification algorithms, if they are used in real-time applications.



Figure 1.5: Examples of SODARs used in wind energy applications. Vaisala Triton (left top), AQ 510 , (middle top), ASC 4000i (top right), METEK PSC (bottom left), Scintec XFAS (bottom right).

There has been a rapid development in LiDAR and SODAR technology over the past 5 years. Figure 4 and Figure 5 show the most common used devices in the context of wind energy projects and studies.

While in the years up to 2013 most field studies spoke about the Remote Sensing devices such as SODAR and LiDAR as promising for site assessment [e.g. Kelley et al., 2007, Mann et al., 2008, Bradley et al., 2008, Bradley et al., 2012, Pena et al., 2013, Lang and McKeogh, 2013], it was only in 2013 that the first SODAR was classified for the IEC 64100-12 standard of site assessment and the ZEPHIR LiDAR was assessed and validated against a IEC compliant mast in a demonstration with a sample size of more than 170 verification cycles at UK's Remote Sensing Test Site.

ZEPHIR LiDAR's white paper [Burin des Roziers, 2014] states that the Zephir LiDAR proves that it "... delivers LiDAR systems well within the IEC criteria for wind measurement equipment. The evidence is gathered across the largest single-type batch of LiDAR performance validations against an IEC compliant mast." The common findings of all the experimental measuring campaigns as well as real-time testing is that the instruments need to be well serviced and are maintained similar to any other real-time instrument operating under changing conditions throughout the yearly cycles. If this is not done, echoes, interfering noise sources, laser beam disturbances deteriorate the instruments and make the further processing of the data impossible. It is also commonly understood that it requires skilled personnel to install and maintain such instrumentation, if it should run continuously and reliably. For a real-time application it is additionally crucial that the measurement signals can be used as is and need no further processing.

Comparisons of commercially available LiDARS

Courtney et al. [2008] made a comparison of two commercially available LiDARs in 2008, the ZePHIR from QinetQ Ltd., UK and the Windcube from Leosphere, France. Although signal processing technology has changed a lot since, including on these two devices, it was concluded at that time that LiDAR technology provides valuable measurements for wind energy purposes, especially if the wind profile is of interest. With increasing turbine heights and rotor sweep areas, wind profiler data can be an advantage over single point measurements. This is a claim that makes remote sensing devices certainly an interesting alternative to met masts. For the operation phase, where the target is to understand the wind conditions at the site such devices add value and with recent developments in signal processing are on the way to become an alternative to traditional meteorological masts.

A more recent study, a comparison between a Leosphere WINDCUBE and a TRITON from Vaisala, Finland, carried out by RES in 2011, confirms the improvements in signal processing as expected by Courtney et al. in 2008 and found that the test showed excellent correlations of the standard deviation of wind speeds. The study concluded that it may even be possible to use the WINDCUBE to obtain reliable turbulence intensity information [Campbell, 2011].

Another advantage of the remote sensing device's ability to measure the wind profile is its ability to "measure" low level jets that can have significant influence for the power production forecasting. The low level jets are a meteorological phenomenon that is a well-known and extensively researched topic in meteorology since the 1950s [e.g. Blackader, 1957, Zhang, 1996] and has been a topic in wind energy research since forecasting started.

Lamar Low Level Jet Project

Recent progress with the help of wind profilers (SODAR, LiDAR) as well as comparisons with a 120m mast has been made in the Lamar Low Level Jet Program, reported by Kelly et al [2014]. In their 1-year experiment, they had some issues with the SODAR's performance and were required to use the raw data with new algorithms to get the required accuracy and quality of the wind data. One of the issues they had with the device was that there were noises that contaminated the signal processing with echoes. Such echo reflections can make it impossible for the signal software to process the signal correctly and hence the data cannot be used.

This shows that the maintenance and upgrades of software to make use of fixes in the signal processing algorithms of the devices are a key technical requirement for real-time use of the devices, or alternatively that the raw data needs to be sent and the processing takes place where the data is used.

However, in the study, the met mast with sonic anemometers suffered from a similar issue, a high-frequency noise contamination that came after a lightning from a thunderstorm that disturbed the sonic signals of wind velocity and temperature in the same way to make the data unusable. Therefore, we can conclude that the reliability of any measurement device in real-time operation requires a maintenance schedule to be a technical requirement in order for it not to deteriorate. If this is done, the SODAR as well as the sonic anemometers have proven to provide reliable time series of wind speeds and gusts in general conditions.

Wind Forecasting Improvement Project

In the largest and longest measurement campaign targeted towards real-time forecasting of wind energy, the wind forecasting improvement project (WFIP) used 12 wind profiler with different frequency (916Hz, 449Hz), 13 SODARS, 3 LiDARs, 72 surface meteorological stations, 184 tall towers and 405 nacelle measurements over a one-year period were used.

The LiDARs as well as SODARs are basic equipment in the meteorological data assimilation today and have been quality checked after meteorological standards through the Meteorological Assimilation Data Ingest System (MADIS; <http://madis.noaa.gov>). This is a necessary step in order to improve the simulation into the real-time model forecast systems [Wilzcak, 2014].

Remote sensing devices in complex terrain

It has been reported in several studies [Bradley, 2008b, 2012a, 2012b, Bingöl, 2009a, 2009b], that the difficulty of the installation of met masts in complex terrain sets a burden on projects. SODARs and LiDARs are much faster and easier to install, since they usually ship as a self contained unit, and can be easily assembled. These advantages from a practical and economic perspective are well known. The disadvantages that are reported are the difficulties LiDARs and SODARs have in replicating correct wind speeds in complex terrain. One of the issues is that the light conus is disturbed by the changing terrain. If this is the case, independent of whether this is an acoustic or light signal, the measurements are no longer correct and are mostly underestimated. In a study carried out in complex terrain in Bosnien-Herzegovina [Wagner, 2014], this discrepancy was 4.5% in comparison to a mast. However, Leosphere, one of the LiDAR manufacturer equipped the instruments with a so-called "Flow Complexity Recognition" (FCR) feature that corrected the signals in the signal processing step for the underestimation. With this FCR algorithm applied, the results were in reasonable agreement with the mast and within the expected uncertainty range.

Another issue that has been reported in real-time operation of remote sensing devices are measurement problems after lightning. These devices are more prone to lightning strikes, which means that for long-term operation this topic needs to be taken into account as part of the technical requirements, especially in areas, where lightning is a common weather phenomenon. The manufacturers are obviously aware of the issues and are most likely working on protection systems. Therefore, this is not considered problematic, however lightning protection and recovery strategies after lightning should be part of the technical requirements of these instruments.

Remote Sensing Devices Summary

To summarise, the theoretical investigation of today's available remote sensing devices seem to suggest that the instruments are at a development stage, which makes them interesting for real-time forecasting and grid operation purposes. However, there are quite a number of technical requirements that need to be present to ensure data collection of a quality necessary for the use in real-time forecasting for grid operators.

An analysis of the applicability of currently available instruments for that purpose will follow in section 5.2.1 and 8.3.1. As of today, the reported commercially available instruments tested in meteorological real-time forecasting or wind energy related projects are the following:

Commercially available LiDAR for wind energy applications:

- Galion from SgurrEnergy, UK
- WINDCUBE from Leosphere, France
- ZePHIR from QintQ Ltd, UK.,
- Wind Tracer, Doppler wind lidar from Lockheed Martin Coherent Technologies

Commercially available SODARs for wind energy applications:

- Triton from Vaisala, Finland
- AQ Windfinder from AQSystems, Sweden
- Doppler SODAR from Scintec AG
- ACS 4000i SODARs
- METEK PCS SODARs

Summary of the recommended technical requirements to ensure high quality data in long-term real-time operation:

- measurements must be raw or technical requirements must include maintenance and software updates
- lightning protection and recovery strategy after lightning measurements should be taken at a height appropriate for the wind farm, either at one of preferable at both hub height and around 30m
- instruments must be serviced and maintained by skilled staff
- version control must be maintained for signal processing
- wind characteristics data must be on wind turbine level
- LiDARs and SODARs in complex terrain require special consideration

1.5.3 Nacelle measurements

Among the nacelle measurement devices there are three types that are commonly used:

- cup anemometers
- horizontally mounted LiDAR (Wind Iris, ZephIR)
- (ultra-) sonic anemometers (iSpin technology, ROMOWIND)

Figure 1.6 shows a schematic of the instruments and how and where they are mounted at the turbine's nacelle. The cup anemometers are typically mounted at the back of the nacelle. The horizontally mounted LiDAR is mounted approximately in the middle of the nacelle with a slight displaced angle in order to cover the total swept area of the rotor in the direction of the eye of the wind. The iSpin ultra-sonic anemometers are mounted at the front of the nacelle, looking kind of undisturbed into the eye of the wind.

1.5.4 Cup anemometers

Most commonly cup anemometers with wind vanes for direction measurements are installed at the nacelle. There are the IEC 61400-12-1, the 61400-12-2 and the ISO/IEC 17025 standards that describe how these instruments must be calibrated and mounted as well as describing the process and the integrity of the measurement processes and design of the mast, instruments and measuring procedures. This will also be discussed in the standard's analysis in Section 6. In this section, we only discuss, whether and how the data from cup anemometer instrumentation at the nacelle can add value to forecasting.

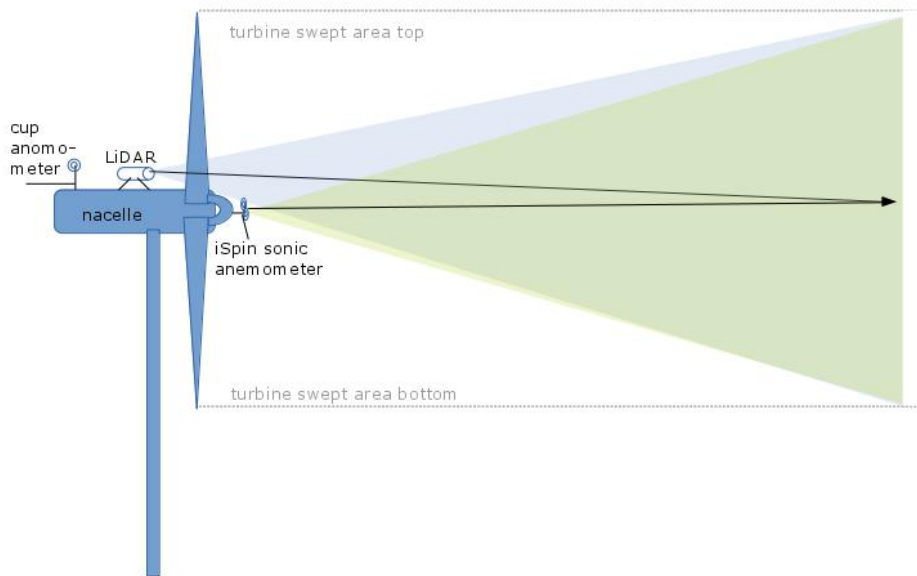


Figure 1.6: Schematic of the nacelle mounted instruments cup anemometer, LiDAR and iSpin ultra-sonic anemometer. The latter two instruments look forward into the wind eye and cover the rotor swept area.

The cup anemometers at the nacelle have one distinctive advantage over any other instruments: they are installed at the turbine and connected to the SCADA system that is delivering data to the system operator. However, this advantage comes with a downside: the measurements taken at the nacelle are affected by two major disturbances: (1) the rotating turbine blades, which generates so-called yaw-misalignment and (2) wake effects from other wind turbines in the direction of the wind. In the worst collection hours both phenomena disturb the signal of the nacelle instrument and the signals can cause deterioration of the forecast, if they are used in the data assimilation phase.



Figure 1.7: MEASNET certified cup anemometer from Campbell Scientific and a cup anemometer 40C from RNRG.

1.5.5 Sonic and ultra-sonic anemometers

The sonic and ultra-sonic 3D anemometers have a long tradition in atmospheric science and meteorology in relation to boundary layer studies of turbulence intensity and phenomena like low level jets. These instruments are well tested and can be used for real-time operations, but are mostly considered too expensive for traditional wind measurements [e.g. Berg et al. 2012, Popinet et al., 2006, Basu et al., 2004, Lundquist, 2014].

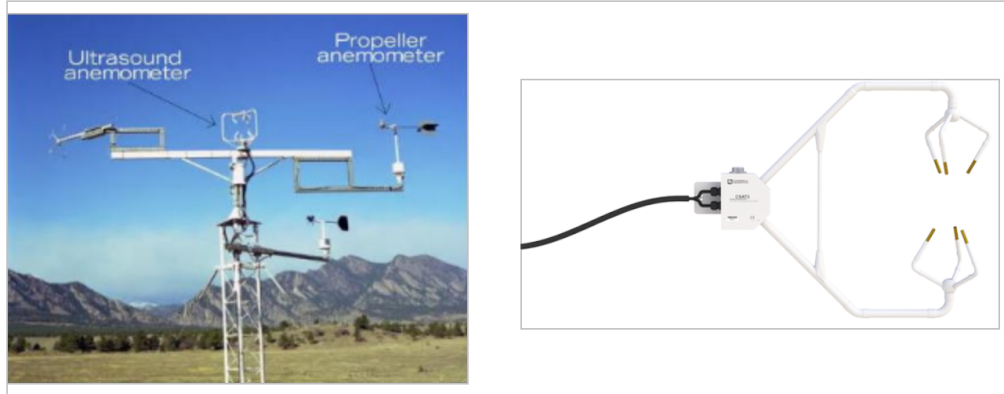


Figure 1.8: Example of a 3D ultra sonic anemometer and a propeller anemometer at the NREL test site in Colorado (left) and a 3D sonic anemometer from Campbell scientific (right).

Figure 1.8 shows a mast with an ultra-sonic anemometer at the NREL test site in Golden, Colorado and a well-tested 3D sonic anemometer from Campbell Scientific.

A newer type of sonic anemometer are the so-called ultra-sonic 3D spinner anemometer instruments, short “iSpin”, which have found their way into instrumentation for wind energy. Figure 1.8 shows the principle of the iSpin anemometer from ROMOWind and an installed spinner anemometer example from METEK. With the update of the IEC standard 61400-12-2, the iSpin technology has become part of the measurement types to define the absolute power curve. The iSpin technology strictly speaking are sonic anemometers that are mounted at the tip of the nacelle, in front of the turbine blades, looking forward in wind direction and rotating with the blades. This means that the velocity of the rotating blades is taken into the computation of the signals and wake effects and yaw misalignment from the blades are measured instead of the signal being disturbed by the rotating blades.

There are a number of studies that have been carried out since 2011, when the instruments were first launched by ROMO Wind. A review made by GL-Garrad Hassan [Falbe-Hansen, 2012] and DNV-GL [DNV-GL, 2015] provide a comprehensive overview of the technology and its development from 2011 to today.

DTU Wind (Risø) has published some documents describing the technology characteristics and basic principles [Pedersen et al., 2007, 2016]. The so-called spinner ultra-sonic 3D anemometer technology “iSpin” has been installed in 2016 on a large fleet of wind turbines in Denmark. The turbines are operated by Vattenfall and the iSpin devices are delivered, implemented and maintained by ROMOWIND [ROMOWIND, 2016]. Unfortunately there are currently no publications available regarding real-time experience. From personal communication with Vattenfall research department, it can however be stated that the results look promising regarding the fit of wind measurements to the power production.

ROMOWIND provides free access to data collected with their iSpinners at the Nørrekær Enge wind farm in Denmark, which was commissioned in 2009 and consists of 13 Siemens SWT 2.3-93 wind turbines at 80 m hub height [ROMO WIND, 2016].



Figure 1.9: Ultra-sonic anemometer spinner technology iSpin from ROMO Wind as schematic and also an example of a nacelle top mounted from METEK (bottom right).

With this, ROMOWIND and Vattenfall (the owner of the wind farm) provide the opportunity to experts and researchers to carry out experiments and studies with the data from the 3D-spinners and compare these data to a met mast and other nacelle mounted cup anemometers. The open-access project is supported by the Danish EUDP program and data was collected under this program from 1st November 2014 to 17th December 2015. This might be a good opportunity to study the performance and the costs in a real environment and thereby be able to provide recommendations regarding the applicability of this technology in the context of forecasting.

1.5.6 Horizontally mounted nacelle LiDAR

Another nacelle mounted wind measurement device is a horizontally mounted LiDAR at the turbine nacelle. Theoretically, every LiDAR can be mounted in that way. However, the space and requirements on top of the wind turbine are very different to the ground. Hence, there is only one commercially available instrument on the market at present, the “Wind Iris LiDAR” from Renewable-NRG [Morton, 2016]. Nevertheless, we will analyse some of the studies carried out with other devices (e.g. ZePHIR LiDAR) to investigate its applicability in the context of forecasting and system operation. Strictly speaking this device belongs to the remote sensing devices. Nevertheless, it is a horizontally mounted LiDAR at the nacelle that looks towards the wind eye and has the same characteristics as the iSpin ultra-sonic anemometers, but is typically mounted at the back of the nacelle similar to the classical cup anemometer. Because it is mounted at the nacelle and is measuring the wind in a conus towards the wind eye, the Wind Iris can measure a kind of profile throughout the sweep area of the rotor. This makes the instrument to an interesting device not only for performance measurements, but also for forecasting.

Angelou et al. [2010] compared a sonic anemometer and a ZePHIR LiDAR mounted at a V27 Vestas turbine at the same height. He found out that the precision of the LiDAR in detecting fast fluctuations of the wind speed was not as high as for the sonic anemometer at the met mast.

However, the authors concluded that for applications, where 10 min averages are of high enough



Figure 1.10: Example of nacelle mounted ZephIR LiDAR and METEK iSpin technology.

time resolution this isn't a problem. In their experiment, the direction measurement however "ran off" and caused a decrease in wind speeds in comparison to the mast mounted sonic.

1.5.7 Known issues of nacelle wind speeds and possible workarounds

Drechsel et al. [2012] found out that the wake effects of nacelle measured wind speeds are highest up until the cut-in wind speed and above approximately 10m/s, where the power curve starts getting flat.

Allik et al. [2014] found out in a study with nacelle mounted cup anemometers, nacelle mounted sonic anemometers and a reference met mast that the mean of the three measurements did not coincide very well. The nacelle wind speed measurements, due to the wake effects of the blades, have a much lower mean. The correlations however were strong between cup anemometer and met mast anemometer and even stronger between sonic anemometer and met mast readings within the range of 3-12m/s.

Wake effects from rotating blades

These findings are consistent with theory, i.e. that the wake effects from the rotating blades are strongest at high speed and low speed, which affects the mean, but not so much the correlation in the "normal" operating range. When plotting such data in a scatter plot, where the linear relationship is strong in this range 3-12m/s, i.e. along the linear part of the power curve, this becomes most apparent. Below cut-in and above the wind speed where the power curve gets flat, the linear relationship does not hold any more. But because this is a smaller portion of the data, the correlation is still relatively high. This behaviour will also be shown in the data verification section with data from the nacelle wind speeds (4.3.3). It was also shown in the frequency distribution of their study, where the met mast anemometers showed an approximate Weibull distribution, the nacelle mounted instruments had a strong bias at the lower wind speeds affected by wake effects.

Real-time study with nacelle wind speeds

The only recorded project that carried out dedicated studies with nacelle wind speeds in a real-time forecasting environment so far is the US Department of Energy funded "Wind Forecasting Improvement Project" (WFIP). The project had a demonstration phase of 1-year and used 410 nacelle wind speeds for the data assimilation of NOAA's models [Wilzcek, 2014, Marquis, 2014].

Using raw nacelle wind speeds in data assimilation

One of the main findings in the experiment was that the nacelle wind speeds were contaminated too much by wake effects to be useful as individual measurements. Due to the constraints in the data assimilation techniques, it was important to find a strategy that made it possible to use the raw

data from the cup anemometers. The research team of NOAA found that the best way to handle the contaminated data was to average the individual turbine data per wind farm and then blacklist those measurements that were outside the range of 2 standard deviations from the mean of the wind farm. This is a reasonable constraint to ensure that measurements contaminated by wake effects will not be passed into the assimilation program.

Additionally, the measurements were averaged over the nearest model grid point in the numerical weather prediction model. By doing this, it was possible to remove systematic biases and make use of the direct outcome of the model at the grid points.

To summarise, the strategy to use all 411 nacelle measured wind speeds at 23 wind farms has been:

- averaging wind speed measurements over each wind farm
- blacklisting measurements that were more than two times a STD from the mean
- interpolating and averaging at the nearest grid point of the NWP model
- BIAS correcting at the model grid points

The advantage of this approach is that wake effects are smoothed out through the averaging within the wind farm and averaging at the NWP model grid points ensures that bias corrections are brought forward to the model result, i.e. the wind power forecast. In this way, it could be demonstrated that nacelle wind speeds can become useful signals seen from a general forecasting perspective.

Pinson and Hagedorn [2012] used a different path to reduce uncertainty of the 633 meteorological stations with cup anemometers that they compared to model results. Their assumption was made according to the recorded uncertainty of unbiased state of the art anemometer uncertainty, which is a standard deviation of around 0.5m/s. It was shown that this was a reasonable and valid assumption. However, it is not known how much this assumption is dependent on the number of measurement units and their distribution. Therefore, such assumptions must be considered with care.

1.5.8 Can nacelle wind speeds be used for high-speed shutdown predictions ?

High-speed wind speeds in the range of shut-down is a topic that has not been researched in any great detail. As discussed in the previous section, there are a number of issues reported regarding downstream wake effects of nacelle cup anemometers at high-speed winds, because of the pitched turbine blades [e.g. Smith et al, 2002, Drechsel, 2012]. This phenomenon can in fact also affect the measurements in the low wind speeds before cut-in, as the blades often are pitched and the wind turbine may still be standing towards a past wind eye before shutting down. Allik et al. [2014] left out the part of the measurements that were above 12m/s, because of the non-linear relationship that they found in the data.

Dahlberg et al. [1999] found in a measuring campaign with nacelle mounted anemometers at a 1 MW and 3 MW turbine and a reference met masts, that there were 3 main issues regarding the nacelle mounted measurements: induction: nacelle measurement errors followed in large the angle of pitched blades (5% pitched blades equivalent 5% measurement error) flow disturbances: changing direction gives changing inclination angles and wrong changes in wind speeds wake effects from other turbines

In these tests, the uncertainty of these 3 main error sources ranged from 1-10% for induction effects, 3-15% for flow distortions and 2-15% for wake effects. Their conclusion was that even though there is a fair chance to correct for possible measurement errors, the lowest error that they were able to reach with precautionary measures was 4%. It was also found that the discrepancies between the reference mast measurements and the nacelle mounted measurements started at around 10m/s and were strongest at wind speeds greater 15m/s.

Smith et al. [2002] found that the upwind met tower and the nacelle anemometers appear close to being linear over most wind speeds, with the most variation at low (i.e., below cut-in) and high wind speeds. They concluded that for power performance testing this is not an issue. For wind power forecasting and operations of a system operator, these are in fact the most critical wind

ranges, because of the ramps before/after the wind has been low or high or strongly increasing. Zahle and Sørensen [2009] found out that a distinct flow pattern with a complex set of vertical structures exists, which induce high tangential velocities in the region, where nacelle anemometers are typically placed. The flow pattern existed for a number of different wind speeds, yaw and tilt angles. Especially when the turbine was operating in tilt, the flow around the nacelle was influenced considerably. In their study, the yaw misalignment was less significant than the tilt and flow angle. Therefore, they suggested that the impact of these distortions of the measurements is sensitive to the placement of the measurement on the nacelle.

To summarise, previous studies agree that the disturbances, whether it be flow, induction or wake induced, are of significant size for nacelle mounted measurement units. While there has been progress over the years in applying precautionary measures to reduce the risk of measurement errors and thereby reduce the uncertainty of the measurement signals, the physical aspects leading to the disturbances cannot be resolved for units that are placed behind the rotor. Unfortunately, all studies that looked at high wind speeds ($> 15\text{m/s}$) up to cut-off wind speeds concluded that the relationship to the reference measurements from met masts were no longer linear and deteriorated strongly. This also means that nacelle mounted measurement units are unsuitable in the control room regarding ramping in high speed wind events as well as pitch regulations due to curtailment or safety, because it is throughout these times, where the measurements are most unreliable. At the time of writing, there are limited peer-reviewed studies that would provide any hint of these instruments providing proven and consistent quality in a real-time operation.

1.5.9 Review Summary and Discussion of Meteorological Instrumentation

In this review we have been describing and discussing the most commonly used instrumentation for wind measurements. The three categories of meteorological mast instruments, remote sensing devices and nacelle mounted instruments have some overlapping devices or technologies. Nevertheless, their use and applicability varies to some extent. Our objective with this review was to provide an understanding of these three categories and where their benefits and drawbacks are in the context of wind power forecasting for system operation. Additionally, we reviewed the standards that have been developed for the commissioning of wind turbines and looked into their applicability in the target context of wind power forecasting and system operation.

We have identified a number of useful procedures in the IEC 61400-12-2 standard regarding calibration of instruments, setup and design of measurement devices and instrumentation that we have identified as crucial parameters for high quality measurements and are recommended to become a technical requirement in the on-ramping phase of wind projects in the future.

In the next step, we discussed which instruments have proven to be reliable for real-time and permanent operation as this is one prerequisite for the target context. In that, the remote sensing devices may today be considered alternatives to met mast measurements, if they are serviced and maintained with care by professional personnel. However, none of the available commercial instruments have a proven record in complex terrain and at higher wind speeds $> 16\text{m/s}$, which is the second prerequisite for the acceptance of alternative instrumentation.

Because of the importance in the context of this study, a number of separate sections have been dedicated to the question of whether the nacelle mounted instruments, classical cup anemometer or newer technologies, such as the ultra-sonic spinner (iSpin) technology or the horizontally mounted LiDAR (Wind Iris), can be accepted as alternatives to independent met masts.

Are nacelle data signals an alternative to met mast measurements: the theoretical view

The question of whether nacelle mounted measurements can be accepted as alternative to met masts should be answered with care. In this review, it was shown that there are new measurement devices such as the iSpin ultra-sonic anemometers and the Wind Iris nacelle mounted horizontally aligned LiDAR that have entered the market and that are interesting and promising instruments.

Promising, because these instruments are developed with the purpose of avoiding the known issues with wake effects at the turbine downstream flow. Insofar, it would be desirable to give allowance to these devices to be used as alternatives for hub heights over 60m. An advantage of these measurements is that they are directly connected to the SCADA system of the turbine and hence directly connected to the data flow from the wind farm to the system operator. Nevertheless, it first needs real-time operational proof that these instruments are: reliable in long-term real-time operation providing reliable signals at high-speed shut down wind speeds and below cut-in operable, even if the wind turbine is standing still.

Additionally, it will be imperative that there are measurements on at least all corner turbines of a wind farm to cover each wind direction. If averages are taken, as done in the WFIP project [Wilczak, 2014], all turbines may need to have measurements providing data. Especially for small projects and projects with tall hub heights, the technical rules may allow these instruments to be alternatives to hub-height met masts, as there is some proof of improvement of forecasts when using such measurements. In fact, for projects with hub heights above 60m, allowing a met mast of 30m, 45m or 60m in combination with the nacelle wind speeds would be an economically much more attractive solution delivering methodologically consistent data for optimised forecasting. In this way, the second point, reliable signals at high speed shut down events may be circumvented efficiently. Requiring nacelle wind speeds from small projects at which the installation of met masts are today not a requirement would add a lot of value to the forecasting solutions in Ireland, because most of the small projects are located in areas, where there are no other larger projects with met masts in close proximity. These areas are often not covered with meteorological measurements at all. A detailed discussion of this topic will follow in the data analysis in Section 3.



2. Distribution of Wind Farms in Ireland

2.1 Geographical distribution of wind farms

The Wind Energy Forecasting (WEF) system in EirGrid and SONI had by the end of year 2018, 279 wind farms registered on the island with a collective capacity of 4.8 GW. These wind farms have differences in age of approximately 20 years and in capacity from KW in size to 100 MW in size.

For the past decade the forecasting technique used by WEPROG was based on weather forecasts tuned directly into SCADA MW values from the wind farms. The forecast error grows with the installed capacity along with the amount of curtailment during the high wind speed events.

In order to maintain reliability with increasing wind penetration, several initiatives are required. Among them is the improvement of the usefulness of real-time data from the wind farms to support improved short-term forecasts.

The 279 wind farms are connected to 109 distinct transmission connections points. Some of the 279 wind farms are registered as multi-phased wind farms. Counting multi-phased wind farms as the number of independent wind farms reduces to 239. This level of independence reduces the risk of large correlated errors and thereby increases system reliability.

The amount of real-time data delivered by wind farms differs. There are various reasons such as age, size and jurisdiction behind these differences. Over the past four years there has been an improvement in the delivery of potential power generation (in the following referred to as *AvailActivePower* 7.2). For the system operator this signal is an important indication of the available power at a wind farm in cases, where the wind farm has been limited by the system operator. In other words, knowing the potential power generation provides the information about the power coming on to the grid, when the limitation is released. By the end of 2018 3.5 GW from 131 wind farms provided *AvailActivePower*, whereof 60 with a collective capacity of 2.5 GW provide additionally wind farm availability.

Another overlapping group of 113 wind farms (2.75 GW installed capacity) provides wind speed and *AvailActivePower* data signals. The wind speed signal is most important at the flat ranges of the power curve, where the power generation is not started yet or does not increase any more. The latter being a critical signal, when the wind speeds move towards a level, where high-speed

shut down occurs. The quality is variable and we identified in this study that only 1.4 GW from approximately 60 wind farms is of reasonably good quality. This corresponds to 29% of the overall installed capacity (4.8 GW).

This low fraction of the total installed capacity combined with an increasing need for short-term forecasting with a higher level of accuracy is the reason for this study. The main objective is to investigate whether the number of wind farms providing good quality wind speed data signals can be increased in a reliable manner by accepting wind speed data signals sourced from nacelle mounted instrumentation.

The number of windfarms submitting meteorological data signals increases steadily, but the geographical distribution of the reporting wind farms is in-homogeneous. By the end of 2018 the number of wind speed reporting wind farms in Ireland has reached 125 out of the 279 wind farms. The study however only considers 93 wind farms that provided real-time wind speeds, whereas 6 of these were added during 2018 and 19 were added during 2017. The other 32 wind farms only started to provide wind speed signals after 1st November 2018.

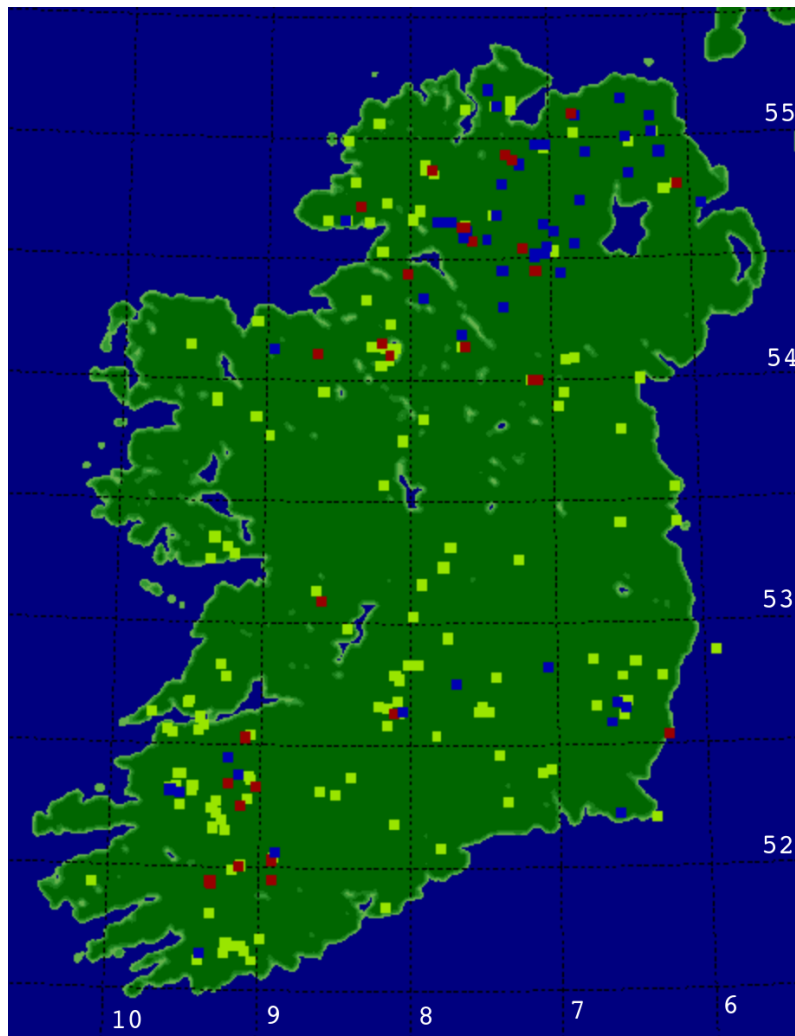


Figure 2.1: Horizontal map of wind farms in Ireland. A blue symbol indicates wind farms submitting wind speed signals from nacelle mounted instrumentation and a red symbol represents data signals from a met mast. The yellow symbols represent wind farms, where the source of met data signals are unknown or do not provide met data.

Figure 2.1 shows the distribution of wind farms divided in 3 groups.

The ROI coast line is poorly covered, which is not optimal from a short-term forecasting and hence system security perspective. The coastal wind farms often experience full load conditions and some of the coastal wind farms are the first to give a sign that wind speeds have changed. An improvement in the submission of wind speed data signals from coastal wind farms would allow for earlier weather changes to be detected and predicted in the short term.

The coastal wind farms provide the best opportunities to improve the forecast for two reasons:

1. They provide the most uncorrelated information, because they are furthest away from each other.
2. The signal in wind speed is less disturbed due to the coastal conditions, where the surface temperature changes are modest and the surface roughness is most homogeneous.

Further away from the coast, the diurnal cycle plays a stronger role, which may cause difficulties in or delayed detection of a weather change, because the wind speed changes are first visible in higher altitudes.

Figure 2.2 shows that there are wind farms in coastal regions. Wind farms located in coastal regions may be limited to the provision of nacelle data as no met mast was installed for planning permission reasons. Grid code provision for wind speed data signals from the nacelle instrumentation would most likely have a positive influence on the number of wind farms providing wind speed data signals along the coast.

Figure 2.2 also illustrates that the concentration of wind farms varies across Ireland. Within each high penetration area it is observed that the wind farms have very different generation pattern. The main reason behind these pattern is altitude differences.

In Figure 2.2 wind farms are coloured according to their installation year. The old wind farms are dark blue. The wind farms approximately 10 years old are represented by yellow squares and the dark red squares were connected in 2017 and 2018. The blue old wind farms are sparse, because the capacity growth was small. The geographical spread is starting to increase from the orange colour. From that point on-wards the eastern and central regions also saw growing capacity. The newest wind farms seem to be spread in all regions which helps to increase the geographical dispersion. However, we still find a couple of red wind farms in each of the wind farm clusters. The normal pattern is that the generation level within these clusters differ considerable. The high density clusters does not imply that wind farms in the clusters have correlated generation. In particular the HSSD point varies considerably among the wind farms in a cluster.

The combination of wind resource and growing hub height does not encourage construction of wind farms in remote areas. Several factors are against utilisation of the remote areas such as planning permission, road and grid infrastructure and future maintenance costs to get on-site. There are almost no new wind farms at very remote locations on the west coast. Along the south and east coast wind farms are being built.

The evolution of wind turbines is resulting in increasing height and capacity. Smaller wind turbines are more costly per produced MWh. The evolution of tall wind turbines is encouraged by direct and indirect efficiency factors. The direct factor is higher production per capital unit and the indirect is less correlated generation with existing capacity due to higher hub height and longer blades.

2.2 Geographical variation of wind farm forecast error

The map on Figure 2.5 is constructed to clarify, whether there is a systematic forecast error relationship between geographical location and/or terrain of the wind farm. The blue wind farms represent wind farms with low forecast error. The error grows with the colour until the maximum, which is dark red.

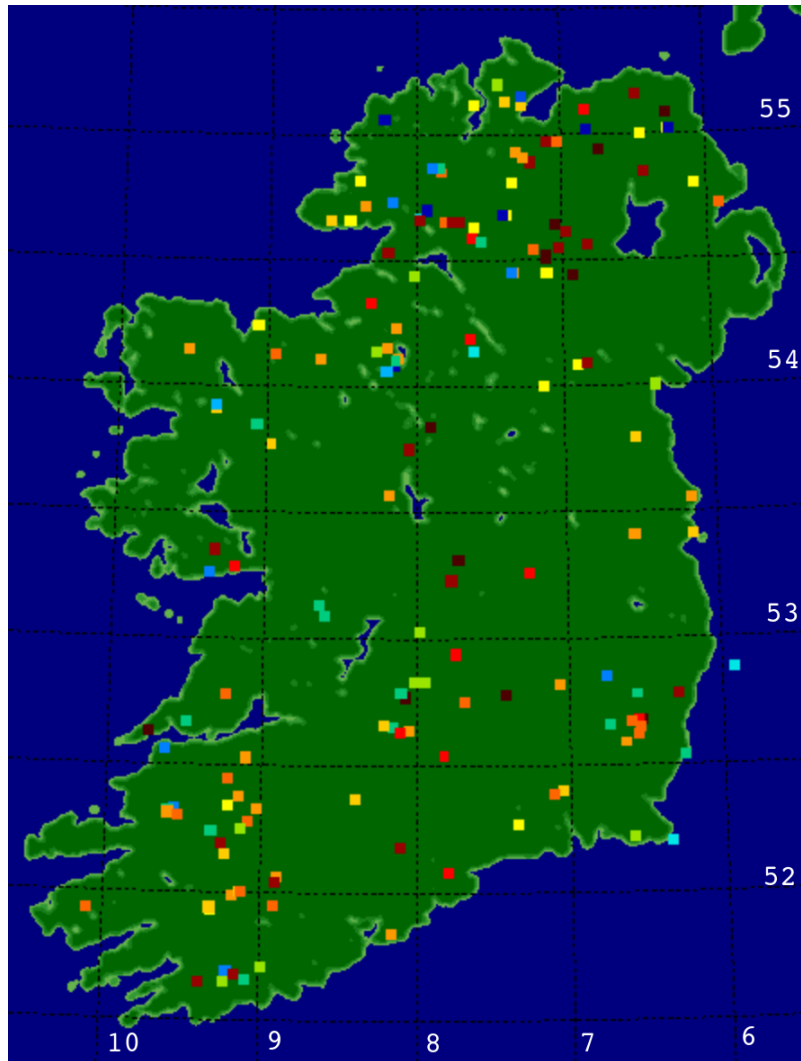


Figure 2.2: Horizontal map of wind farm distribution according to their year of grid connection. The blue wind farms are connected before 1997 and the dark red in 2017 and 2018. For all other wind farms the year of connection is used to compute the appropriate colour using a sliding scale, showing that the dispersion level has not changed over time.

There is a tendency of lower forecast errors for wind farms with an east or south facing coast line. This is so, because warm airflow over slightly less warm sea is a more predictable weather pattern and is the typical weather before new low pressure systems approach from the west. The wind in front of the warm front is from south east leading to a clean, stable flow at wind farms facing an east and south coast. Once these wind farms are in the warm sector of the frontal system, the flow can still hit the wind farms close to a south coast from south west. Another factor giving lower forecast error in the south is that the scale of motion is normally larger and the low pressure systems are further away causing the warm sector to be wider in the south east than in the north west. Another effect of the wider warm sector is that the ramp rate is smaller in the south per unit capacity than in the north west. Exceptions from this pattern occur when the low pressure systems take more southerly routes than normal.

There are also exceptions in the north. At least one old small wind farm on the north coast is also highly predictable, although it is located in a very rough area seen from a weather perspective. However, there are no obstacles upstream of this wind farm in the prevailing wind direction.

The generation is therefore more stable and more predictable. The wind farm reaches maximum generation output at relatively lower wind speeds than generally seen and has therefore many maximum generation output hours and consequently low error, as 2-3m/s forecast errors rarely impact the power forecast.

Away from the coast we find most wind farms with low error in the very south western part of Ireland. This is consistent with that the warm air flow increases the predictability and also cause moderate wind gusts.

There are wind farms with low forecast error right next to wind farms with significantly higher errors. This pattern has been observed in three regions (southeast, southwest and south centre). The difference can be due to the varying reliability of disturbed flow either as internal wake or externally generated waves in the flow.

The overall conclusion is that the details of the wind field at a particular wind farm cannot be simulated very well for most wind farms. The detail may even depend on new wind farms in the upstream direction. The error on the individual wind farm is for all the high error wind farms a local wind farm specific effect. If they would be freely exposed to the wind and work reliably, the forecast error would be close to half of what has been measured. The per wind farm forecast is most critical on the very short term to manage dispatch instructions. For this forecast range, there is a benefit of the on-site wind speed, if it contains details such as terrain differences or obstacles not present in the weather forecast model.

2.3 Capacity distribution as a function of wind farm size

The results in this section is purely a capacity examination derived from the standing data delivered in real-time through the forecasting system.

Figure 2.3 shows the capacity distribution ordered from small wind farm to large wind. The y-axis has two different unit sets. A second y-axis has not been generated due to both axes having the same units. For the magenta curve, the y-axis refers to [MW per wind farm]. For the blue and green curve the y-axis refers to [% of total installed capacity]. The smallest 150 wind farms make up 20% of the installed capacity for the green curve. The difference between the blue and green curve is that wind farms that were installed after 2016 are not included on the blue curve.

Figure 2.3 shows that 150 of the smallest wind farms together add up to 20% of the installed capacity by 2018. On the other hand the 150 smallest wind farms installed by end of 2016 make up to 40% of the then current capacity. Therefore, the importance of small wind farms is getting less and less, which may be reason enough to exempt them from the obligation to provide detailed on-site meteorological data.

The magenta curve preserves the low slope until 20 MW. This means that many wind farms are smaller than 20 MW. In total, 200 wind farms are smaller than 20 MW and make up 35% of the total installed capacity. Similarly, wind farms smaller than 15 MW make up 30% of the capacity. A moderate slope follows from 20-40 MW, i.e. less wind farms than below 20 MW. Wind farms larger than 40 MW are least common (less than 30 wind farms), although they make up 35% of the current total installed capacity.

It is important to note that 80% of the total installed capacity is covered by wind farms larger than 17 MW. It can be seen in Figure 2.3 that the relative impact of smaller wind farms reduces with time.

Table 2.1 shows the MW capacity installed per year by small wind farms (< 17 MW) and their fraction on the total installed capacity. The table shows that 217 MW of capacity was added by wind farms smaller than 17MW in 2017 and that 41% of the new capacity in 2018 came from wind farms smaller than 17 MW. From a forecasting accuracy perspective, increased geographical dispersion is a benefit. However, it is only a benefit, if wind farms are of a sufficient size that certain grid code data signal requirements apply.

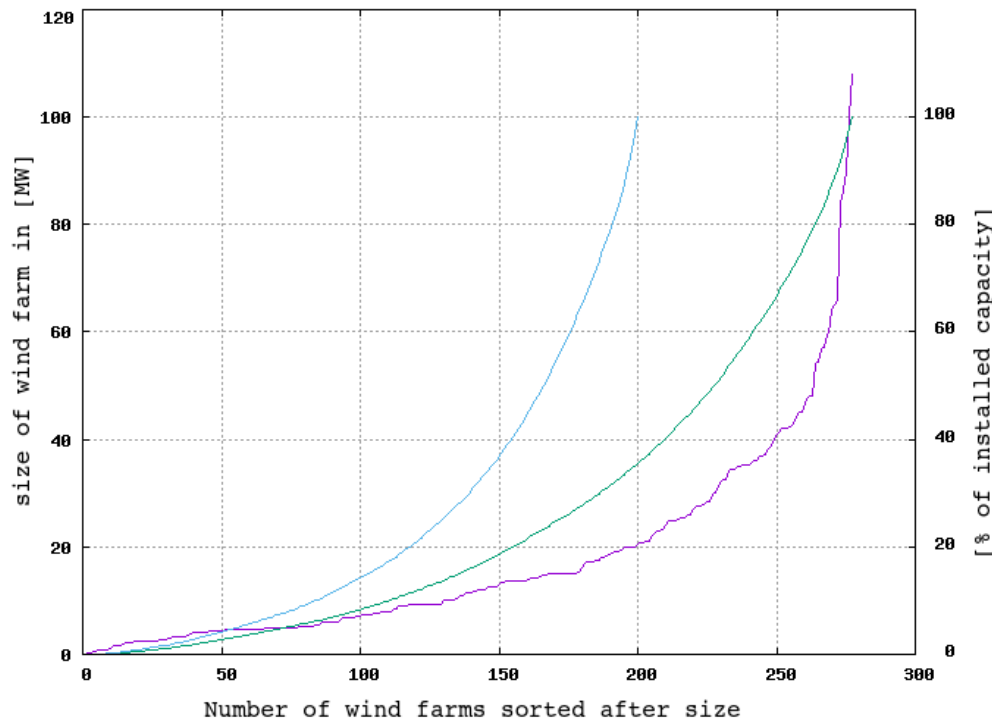


Figure 2.3: Overview of the capacities per wind farm in Ireland. The Wind farms are sorted based on their capacity, where the smallest wind farm is at 0. The magenta curve refers to the primary y-axis (left), the green and blue curves to the secondary y-axis (right). The green curve is the accumulated capacity up to 2018 (279 wind farms with a total capacity of 4760 MW) and the blue curve is the capacity up to 2016 (200 wind farms total capacity of 3127 MW).

A small wind farm comprised of a low number of wind turbines can cause significant error, if the only data provided will be the actual power generation value. For these types of wind farms, reduced availability can be difficult to detect and misinterpreted. Also from a HSSD forecasting perspective, small wind farms geographically spread out will be a disadvantage, if wind farms are not obliged to deliver the HSSD signal and a wind speed data signal. From a HSSD operational handling perspective, more independence and geographical dispersion reduce the risk of a correlated HSSD. Given the amount of small wind farm projects installed in 2017 and 2018 we must conclude that projects of this size are competitive in price and that they could become even more common or attractive, if there would be less data provision requirements for wind farms of this size than for larger wind farms. A smaller wind farm can be located in more isolated areas than other wind farms and therefore be able to earn more per produced MWh than wind farms installed closer to the centre of the installed capacity. Hence, the recent increase in the fraction of smaller wind projects could have an economic reason. Both regions along the coast and on top of smaller hills are possible locations to achieve a less correlated wind power generation to the total wind power generation.

2.3.1 Error distribution as a function of wind farm size

Figure 2.4 shows the mean absolute forecast error (MAE) of forecasts, trained with historic measurements, for the calendar year 2017/2018. The statistics shown is for the 9-15 hour look ahead time from the initial time corresponding to a look ahead of 4-10 hours from forecast availability.

Year	Capacity [MW]	Fraction on total inst. cap.	Number of wind farms
2003	29.1	27.6	6
2004	53.1	31.6	9
2005	61.7	33.7	10
2006	61.2	31.0	11
2007	48.1	31.5	6
2008	98.5	40.0	15
2009	58.0	17.1	14
2010	51.6	23.2	7
2011	92.4	35.5	14
2012	27.6	17.5	3
2013	82.1	23.3	9
2014	41.2	10.6	4
2015	34.8	17.4	3
2016	117.3	18.9	10
2017	230.7	28.6	24
2018	85.3	41.2	10

Table 2.1: Yearly installed MW of wind farms <17 MW and their fraction on the total installed capacity.

The size of the wind farms are for confidentiality reasons grouped as the average of 10 wind farms. That means the first impulse at wind farm 5 is the average size of the wind farms ranked 1-10 in mean absolute forecast error. Similarly, the impulse at 15 is the average size of wind farms ranked 11-20. The first four impulses are clearly lower than the remainder. Behind these four impulses there is only one larger wind farm, which is responsible for the higher average of the 3rd impulse. There is one additional impulse in the end representing the non-energised wind farms defined in the WEF system. There is also a few more which were energised in late 2018. A MAE forecast error of 6% seems achievable for wind farms working technically well with little wake effect and free wind in the frequent upstream directions. Among the 6%, there are wind farms on all sides of the coast, but most wind farms are found on the south coast. There are also 6% errors achieved in complex terrain in the south east, south west and south-west-centre. Besides the wind farms with low error, we found wind farms with close to double that error in apparently the same wind conditions.

On figure 2.5 it can be seen that there are wind farms close to each other which have very different errors because their colours differ. There are characteristic patterns of blue wind farms along the south and south coast. They have more stable wind hours with southerly wind directions. However, even in the very northwest there are also blue wind farms not shadowed and thereby are not affected by disturbed obstacles.

Overall this is a sign that the terrain and possibly also upstream wind farms generate turbulence or more general details in the wind, which is not predictable by direction. Other factors play a role. Internal disturbances (wake) and external disturbances seems to be possible explanations of all wind farms with high error (red colours). Even in steady increasing wind from a southerly wind direction, it is rare to see a wind farm following the ramp up in a clean manner. They loose efficiency on the way up possibly because of wake effects causing that narrow wind direction bands trigger turbulence generation from wind turbine to wind turbine. The more frequent that such turbulence occurs, the higher the average forecast error.

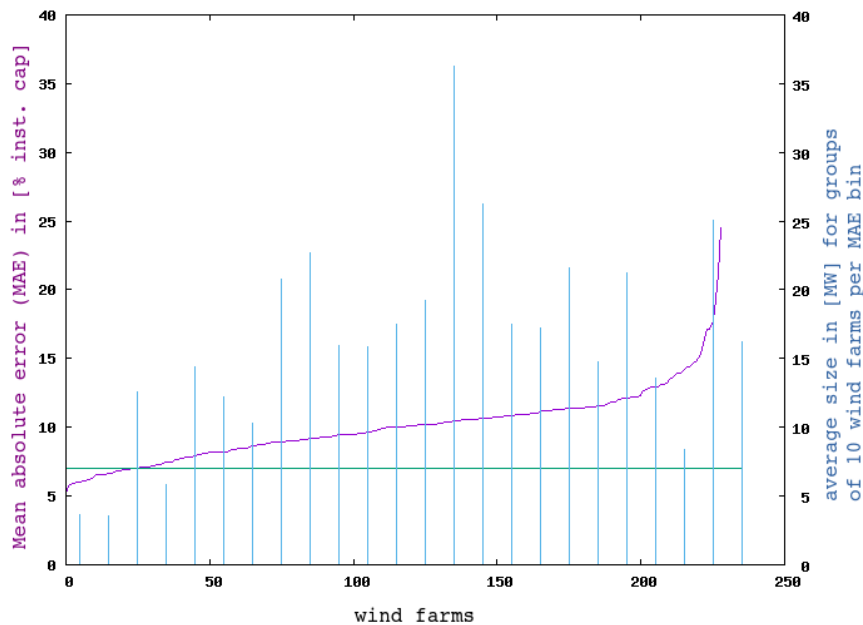


Figure 2.4: Overview of the wind power forecast mean absolute error (MAE) for 240 of the 279 Irish wind farms. For confidentiality reasons, the wind farms are bundled into groups of 10, i.e. there are 24 values in the magenta curve and 24 impulses. The magenta curve shows the MAE for all wind farms trained as part of the study sorted after size. The first wind farm has approximately 5% error. The blue impulses indicate the average capacity for the 10 wind farms around each impulse. The green line is a target error level for a forecast with improved data exchange.

Therefore, we expect wake effects to be the most significant cause of forecast errors above 7%. It is a black-box of technical issues, errors in the data, maintenance, local effects on the wind from the terrain together with disturbed flow from local or remote wind turbines.

Coastal Wind Farms

The lowest forecast error on the coastal wind farms indicate that wind turbines do disturb the wind flow and that the disturbances vary from case to case. A direction dependent power curve does not capture such disturbances, because it is a matter of a few degrees in the wind direction.

Wind Farms with lowest Forecast Error

The forecast error on the 25 best wind farms below 7% MAE demonstrate that the wind speed from the forecasts is sufficiently accurate for these wind farms. These wind farms are with one exception all < 10 MW and with 2 exceptions build before 2010. It would have little impact to exempt these from detailed data requirements.

Wind farms with highest Forecast Error

There are only 9 wind farms smaller 10 MW with a combined capacity of 50 MW build before 2010 with more than 12% forecast error and 3 wind farms of size 30-50 MW with MAE errors between 12-15% that are built in year 2007 and 2009 with 137 MW combined total capacity. The latter are providing meteorological data.

On the high error end of the scale we found 15 wind farms with low predictability (MAE > 12%) with a collective capacity of 350 MW. These have sizes from 11-47 MW and are built after 2010. Only five of these wind farms provide meteorological data of good quality.

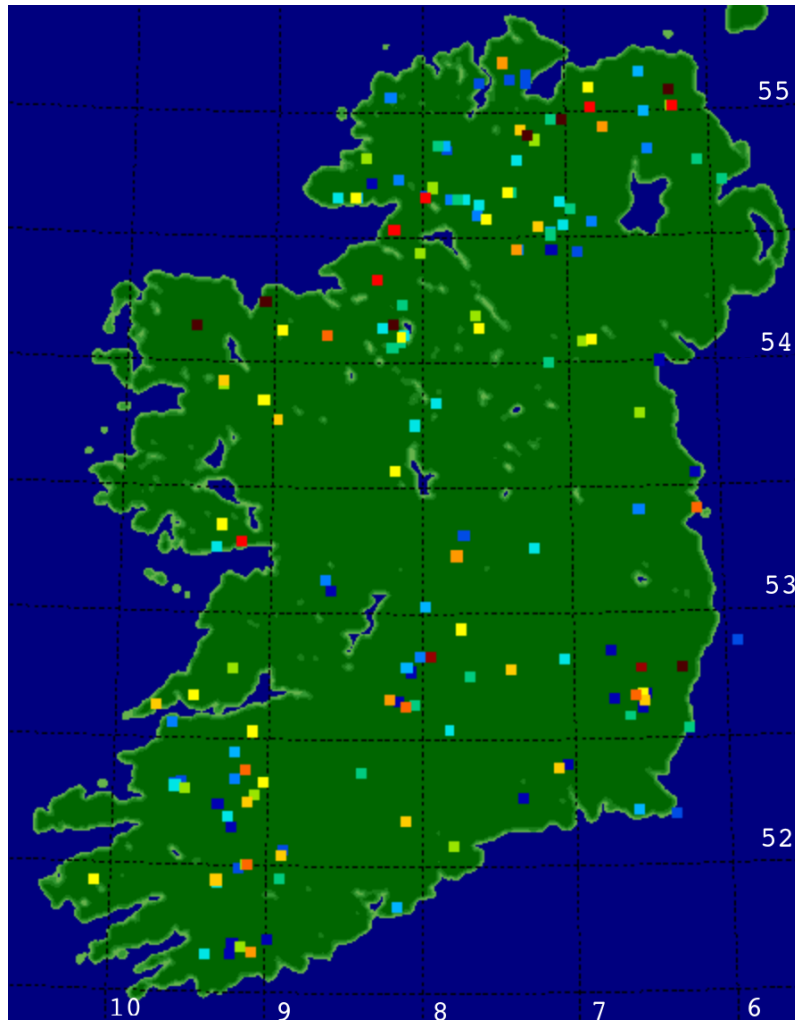


Figure 2.5: Horizontal map indicating the error level for each wind farm. The dark blue colours are wind farms below 7% MAE and the dark red colours are wind farms above 15%. The colours in between follow a sliding scale between 7 and 15%.

Forecast Error in relation to Age of Wind Farms

There are 1300 MW combined capacity built after 2010 with MAE errors above 10% and 750 MW with less than 10% error. We conclude from this result that the overall trend is increasing forecast error per farm for the new capacity. A large portion of the forecast error per wind farm above 7% is uncorrelated and is reduced by area aggregation. It can create short lasting sign shifts in the system balance and gradually increasing needs of primary reserve or one-hour reserve.

Other possible explanations of stronger error on larger wind farms include:

1. A 15 minute snapshot of the on-site data can lead to stronger variations due to turbulence in variable weather conditions
2. The learned power curve does not reach full load, because there is often reduced generation in conditions with wind speeds > 15m/s
3. The upstream wind turbines can generate downstream effects opposite to wake effects

Higher resolution of on-site data and possibly ultra short term forecasts seem to be required in order to correctly predict the magnitude of these oscillations. If the measured wind speed and direction can be used to track wake effects by wind farms, then it would be possible to forecast these oscillations one or more hours in advance.

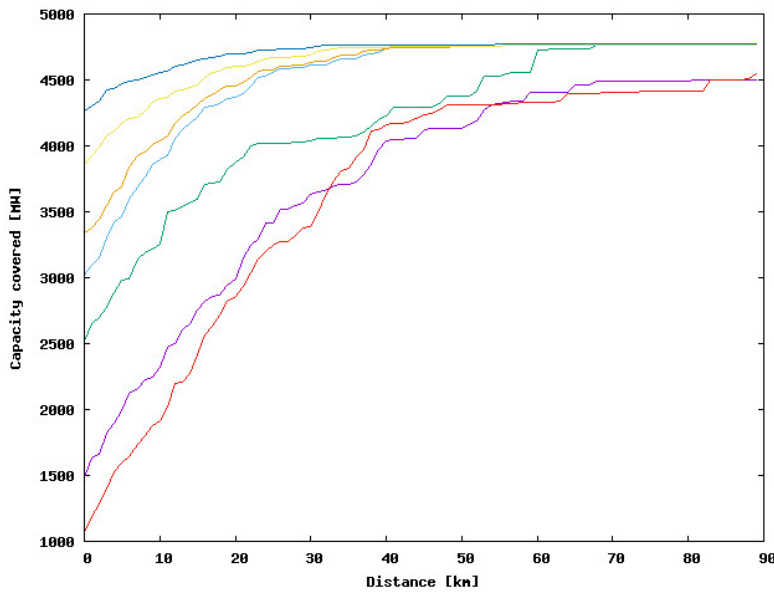


Figure 2.6: Each curve on the graph represents the extrapolation distance of wind speeds required to achieve the capacity coverage shown on the y-axis. The curves differ in their assumptions of which wind farms provide data. The lower curve only accepts the current masts whereas the upper curve assumes that all wind farms above 10 MW provide wind speed data. The evaluation is a pure speed data computation ignoring that the feasible extrapolation distance is terrain dependent.

A likely required accuracy of the wind direction would be 1 deg. A forecast is not that accurate in the planetary boundary layer, because the frictional forces depends on the details of the terrain in the model, which is considerably smoother in a weather forecast model than in reality. Using the forecast to track the detailed wake effect does therefore not generate a visible sign of a directional narrow wake effect.

2.4 Distance based computation of effective wind speed coverage

There is a low wind farm density around latitude 53.0 to 53.5 from west to east, where none of the wind farms provide wind speed data (see Figure 2.1). This situation can be considered a gap in the island wide observational network from the northern to the southern wind farm clusters. A more homogeneous capacity and observational network would help in reducing the overall forecast error. In Figure 2.6 we examined the sparsity of the observational network. The graph has 7 curves showing how far wind speeds must be extrapolated to cover other capacity not providing real-time wind speed data signals. Each curve corresponds to one specific scenario displaying the spread in distance to other wind farm clusters. The x-axis is distance in km and the y-axis is the covered capacity after an extrapolation in kilometres distance. The red lower curve is the extrapolation from the met masts that currently provide reliable wind speed data signals. At 90km extrapolation 4500 MW are covered, with 15km extrapolation about 2.5 GW, corresponding to about 50% of capacity, are covered.

Magenta Scenario: Nacelle and met mast sites

The magenta curve, second from below corresponds to an extrapolation using the current list of sites that provide high accuracy data. The two lines follow each other. This suggests that nacelle sites and mast sites are at approximately similar locations.

Green Scenario: Met mast sites

In the green scenario we extrapolate from the current 93 mast sites and nacelle sites. In that scenario full capacity coverage is reached between 60 and 70km.

Scenarios: full observational coverage

The light blue scenario corresponds to all wind farms that are larger than 25 MW. These wind farms must supply data to ensure full coverage. The orange, yellow and dark blue scenarios are the same scenarios as the blue, but with 20MW, 15MW and 10MW respectively as the lower threshold limit for full coverage.

Most noticeable is that 4GW is covered with 21km of extrapolation when using the current set of delivered data. The full 4.76GW would be covered with the same distance, if all wind farms above 25MW would provide data.

There is a gap between the lower 3 curves and the upper 4 curves on the distance 20-40km. The green curve only gradually approaches the upper curves at a distance of 60km. The red and magenta curves only approach full coverage at around 100km distance and lie outside the x-axis range.

The difference between the upper and lower group is that the upper group is computed with the assumption that some larger wind farms around latitude 53 will be enforced to deliver data. They are larger than 25MW and did not provide any wind speed data signals until November 2018. If they would provide such data, the coverage would be significantly improved with extrapolations of 20-30 km. This can be seen most pronounced by the light blue curve.

The data coverage difference at 21km is insignificant between 10MW, 15MW, 20MW and 25MW wind farms. Future wind farms could however change that pattern, dependent on whether or not they deliver meteorological data.

We can conclude that the 10MW limit or even the list of wind farms that are supposed to provide meteorological data signals would provide enough detail, if the data signals were of good quality. However, the ST forecast could be considerably improved by wind speed data signals from the few wind farms along latitude 53.0 – 53.5, because they would connect the southern and northern group of wind farms. Without the data on latitude 53 – 53.5 deg the ST forecast consists of two large clusters with limited benefit for each other due to the distance to each other. On the contrary, a shorter distance of around 20km would improve the accuracy of the forecasts considerably.



3. Data Analysis

3.1 Validation Methodology of on-site MET-DATA

In this chapter we will describe the validation methodology and provide results computed for the period January 2015 to November 2018 on the signal quality of meteorological data submitted by wind farms to the system operator. The methodology is designed for future monthly or 3 monthly examination of observational data signals. We have two targets for the validation:

1. To identify the amount of valid data submitted.
2. To produce a comprehensive conclusion which will provide the wind farm owner with as precise as possible a description of the root of the error detected in signals.

First we describe why simple approaches will not meet these targets. For a number of reasons cross correlation between wind farms is not a feasible methodology for the verification of observational data signals. Such verification is in fact mostly challenged by irregular distances among wind farms and the need for long verification periods.

The time from when an issue with data signals starts until it is diagnosed and solved will be too long, possibly 6-12 months depending on the significance of the data issue.

Wind Speed from Nacelle computed Methods

If wind speeds from the so-called *nacelle computed methods* will be permitted as a source, there is limited possibility to use a nearest neighbour based validation of the data. These types of nacelle wind speed data signals are a result of a complicated computational process, which is confidential and tuned to provide a representative wind speed signal to the corresponding power signal at a particular wind farm.

The following example demonstrates this issue: Two neighbouring wind farms from different manufacturers provide nacelle computed wind speed and are evaluated against each other. If they are consistent, it would be easy to approve wind speeds from nacelle computed measurements. If they do not agree, then it will become a complicated scenario and a complex process to find out or decide which of the measurements are correct. Since all wind farms differ and are distant enough to not experience identical weather, it will be non trivial to determine which wind farm provides correct data.

Whether it is possible at all to justify one to be more correct than the other, it is certainly difficult to prove errors in volatile data where there is not a direct relationship. Temporary and partial outages on a wind farm can be hidden in the data of one wind farm and not at the other. It would depend on how the software defines the nacelle computed wind speed, as it does not need to be the same definition used across manufacturers.

Nacelle measured wind speeds with Cup anemometers

Determining inaccuracies would almost be equally difficult, if the nacelle data would be the plain average of the cup anemometers from each wind turbine. There are too many components behind the values that smooth out timely variations of the wind speed and too many uncertainties of wake effects, over-speeding etc. that impact the cup anemometers.

Met mast measured wind speed with Cup anemometers

In contrast to the nacelle measurements, a single cup anemometer on a mast can be inspected at a much lower cost, today even with a drone. Several anemometers can be mounted on the mast and it is at least possible to submit the data directly without giving the wind farm software the possibility to delay, block or manipulate the data.

The accuracy of a single value from a cup anemometer is not high without a 10min time average. The purpose of the 10min averaging process is to eliminate the impact of the turbulent motion, which is generated as a result of frictional forces from the terrain on the air as well as the imbalance in the diurnal cycle and the temperature difference between the air and the surface. From a 15 minute data delivery of a noise contaminated signal, it is almost impossible to prove the correctness or falsify the data signals, because some of the values are realistic and others are not.

Apart from outages in the submission, the validation process of wind speeds is going to be based on statistics over long time periods. The evidence of an error would have to be very convincing until a case would be opened. The methodology to use for the validation is a combination of consistency checks between:

- forecasted wind speed versus measured wind speed
- forecasted temperature, wind direction against measured values
- forecasted power versus active power checked with SCADA MW
- Computed active power from measured wind speed versus actual active power
- Comparison against previous years of the same wind farm
- Comparison to the average error level for wind farms in the same period

In the operational setup, 3-monthly verification statistics along with the methodology described above will be able to clarify, whether the accuracy of the submitted data signals is acceptable or not.

3.1.1 Statistical tests and metrics

The statistical test and metric used in the following analysis is similar to the verification of the forecast error, except that we use the forecast as the reference, because it is the measurement that we want to validate against, as it has a known accuracy level. By validating in different sub periods of the year, it can be shown whether the error pattern has been temporary or on a long-term basis. We present different statistical tests in order to have the best possible data basis for the interpretation of the data accuracy. The following statistics were computed:

1. BIAS:

The BIAS in itself should be low, but is no guarantee of correctness of the data, because a BIAS can be low for the incorrect reason

2. MAE: MAE and BIAS together show, if the data has an offset.

3. RMSE: There are few extreme errors, if the ratio RMSE/MAE exceeds 1.3.

4. CORRELATION:

The correlation allows for easy detection of constant measurements as well as sign errors.

5. Frequency distribution:

The frequency distribution from one year of 15-min mean values of a wind speed shall be a smooth curve with decreasing probability of high wind speeds. A temporary instrument fault will be visible as a skewness of the curve. We compare frequency distributions of the ensemble mean forecast against measurements. Positive and negative phase errors between a forecast and measured data tend to cancel each other out over a long enough period. Therefore, one should expect high similarity between two independent time series of the same physical variable.

The formulas of the test metrics can be found in the Appendix 7.2

3.1.2 Long-term verification of met data signals

In the study, a long-term verification of the data signals from 4 meteorological variables has been carried out. The variables were

1. wind speed
2. wind direction
3. air temperature
4. air pressure

Figure 3.1, 3.2 and 3.3 show the results of the verification in form of CORRELATION, MAE and BIAS for these 4 variables for 2 years of data signals. Each metric is calculated by the wind farm. The number of wind farms submitting each variable is different and the wind farm ranking is also variable dependent. The same applies for the quality, which is variable dependent. Please note that for example temperature varies slower than wind speed and achieves therefore in general a high correlation.

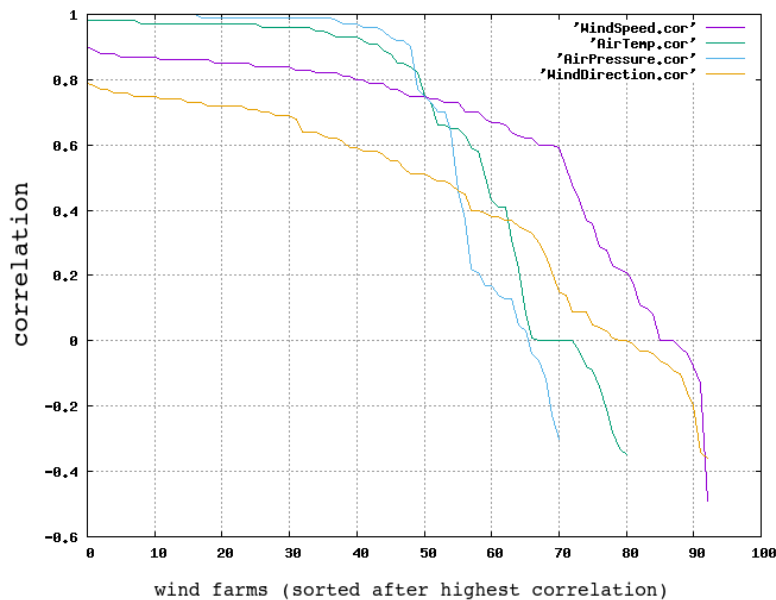


Figure 3.1: Results from a 2 year statistical verification of met data signals on CORRELATION for 4 variables. The x-axis shows wind farms ordered with the highest correlation first.

The purpose of these 3 graphs are to define acceptance limits for the quality of the data in terms of BIAS, MAE and CORRELATION. In each graph we see a continuous degradation followed by a steeper slope for the last fraction of the wind farms.

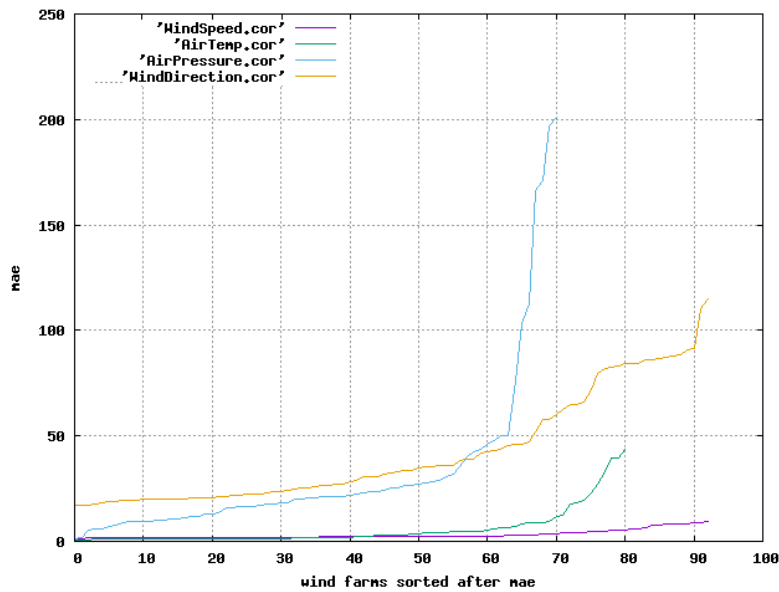


Figure 3.2: Results from a 2 year statistical verification of met data signals measured on MAE for 4 variables. The x-axis shows wind farms ordered with the lowest MAE first. The unit and magnitude is variable dependent and somewhat hides the growth of the wind speed error.

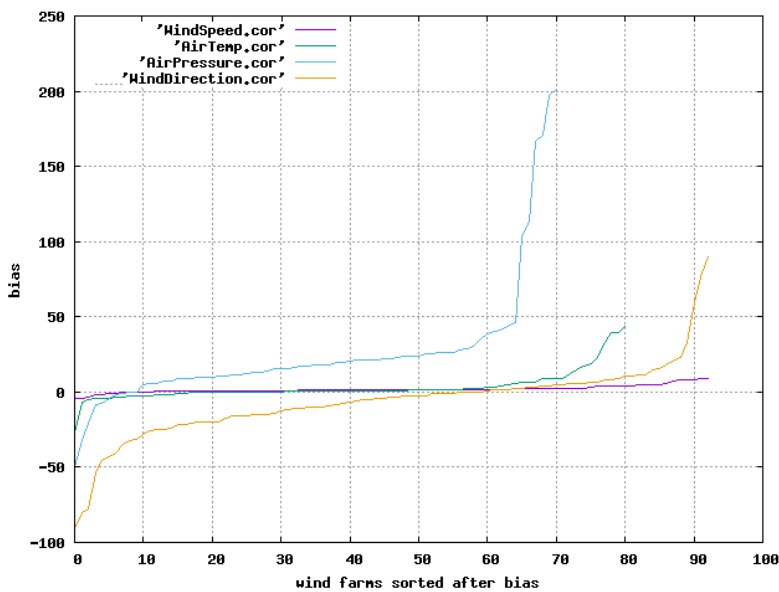


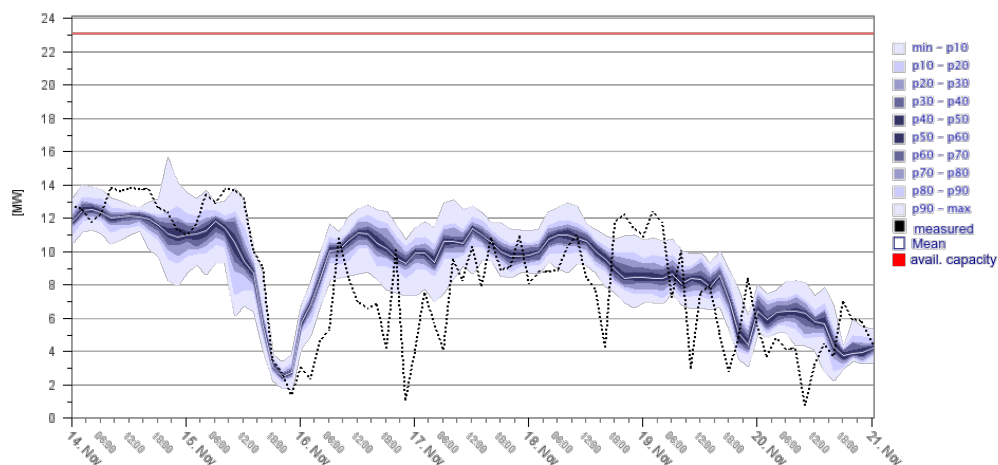
Figure 3.3: Results from a 2 year statistical verification of met data signals measured on BIAS for 4 variables. The x-axis shows wind farms ordered with the lowest BIAS first. The unit and magnitude is variable dependent. Note that the pressure BIAS hides the growth of the wind speed error for the last 30 wind farms.

The common pattern in all cases is that approximately 20% to 40% of the wind farms provide poor data. For these, the CORRELATION on Wind direction and wind speed is only about 0.2. The slope of the curves even indicate a degradation starting already after the first approximately 30% of the wind farms. Thereafter, the slope of the curve increases exponentially.

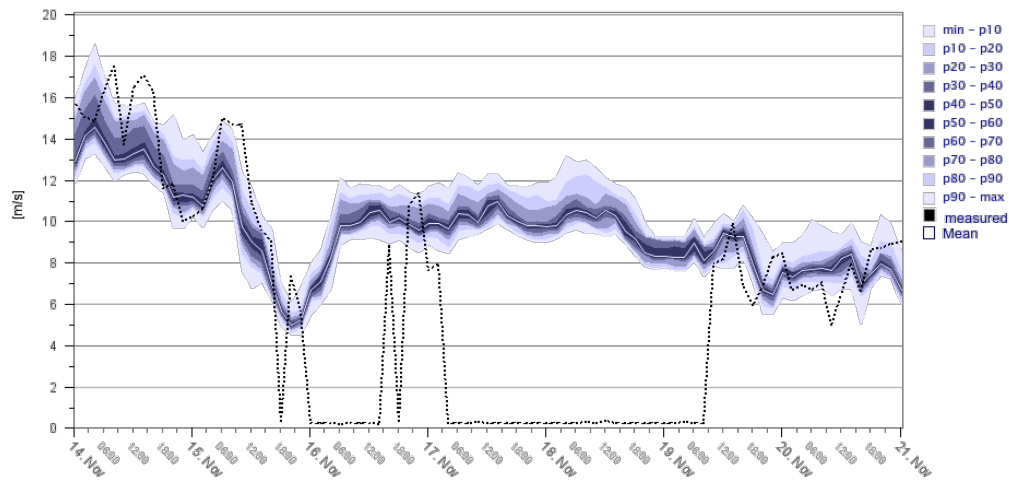
This pattern covers mostly the rather simple explanation of an increasing fraction of very poor data, but it is also blended with the fact that the measured wind speed is strongly influenced by local conditions for some wind farms than others. The amount of local effect can be seen on temperature versus wind speed, because there is a more modest local effect on temperatures at wind farms in Ireland than for wind speeds. The slope of the wind speed correlation is worse than for temperature. On the correlation Figure 3.1 the constant zero window should be noted, also for wind speed and temperature. This reflects the fact that some wind farms provide constant data signals, typically zero values.

3.1.3 Typical Data Signal Error Patterns at Wind Farms

The following 4 figures demonstrate how wind power outages and the disappearance of wind speed data signals occur simultaneously or independent of each other. In the first example, shown in Figure 3.4a and Figure 3.4b, a dispatch period had no effect on wind speed. The wind speed disappearance occurred independent of any dispatch instruction, which should always be the case.



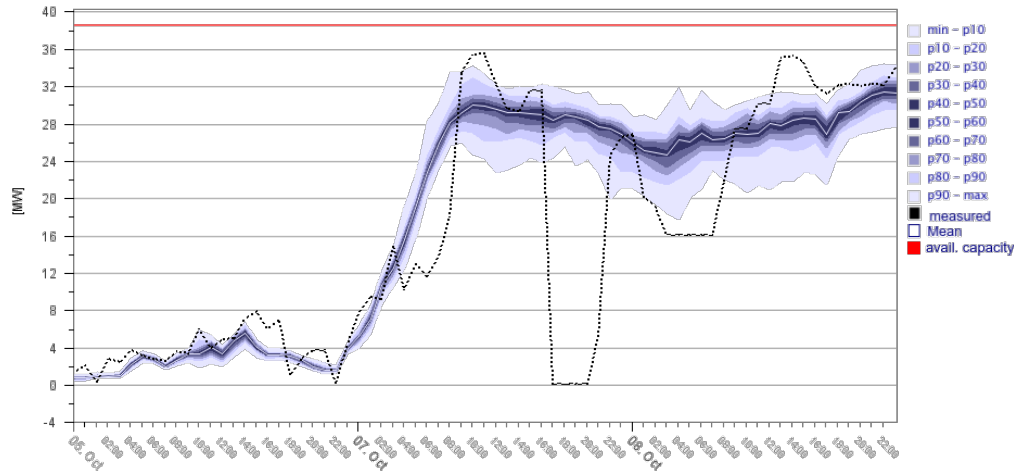
(a) Example of a wind power at normal power generation, while there are outages on the wind speed.



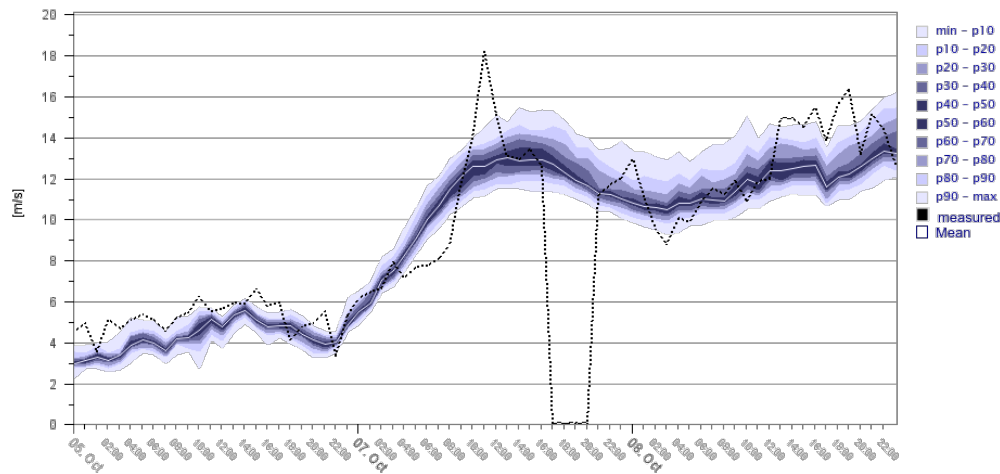
(b) The wind speed outages while wind farm MW generation is normal.

Figure 3.4: Example, where a dispatch period had no effect on wind speed.

The next example, shown in Figures 3.4a and 3.4b a common observed pattern is illustrated, where both the wind power and wind speed signal disappear at the same time at the wind farm. This pattern indicates that the wind speed signal is tied to the SCADA system of the wind farm or dependent on the power generation of the wind farm. These setups can lead to major issues in regions with few wind farms and where there are many small wind farms around which do not deliver any wind speed data signals.



(a) Wind power generation outage followed by a dispatch period with potential impact on the wind speed.



(b) Wind speed outage aligned with power outage, but the wind speed is unaffected during the dispatch event.

Figure 3.5: Example, where both the wind power and wind speed signal disappear at the same time at the wind farm. See legend explanations in Figure 3.4.

Subjective evaluation of the previous figures do not leave much doubt that forecast percentiles are robust compared to the on-site data. The inclusion of incorrect on-site data in the verification process has significant impact when comparing to the forecast, because historical constant data contributes strongly to the monthly error.

In the case of a delivery requirement of 98.5% of the time it would be acceptable to reject up to 11 hours of incorrect data each month. It would also take a higher delivery requirement in order to acquire wind speeds during planned wind farm outages.

3.1.4 Acceptance limits and results for Met Data Quality

The graphs in the previous section have demonstrated that wind farm data quality follows a sliding scale. When we define limits based on the accuracy against an ensemble mean forecast, a widespread limit is required to avoid that correct measurements are disqualified or rejected. The limit will therefore also accept some incorrect data. We have chosen to define the limits for acceptable quality according to Table 3.1. Using these definitions for nacelle and mast data over a period of 47 months we can compute an average acceptance fraction.

Variable	Unit	Bias	MAE	Correlation
Wind speed	[m/s]	3	1	0.65
Wind direction	[°]	13	20	0.55
Temperature	[°C]	2	2.5	0.75
Pressure	[hPa]	50	85	0.85

Table 3.1: *Proposed error thresholds for statistical tests of wind farm meteorological data signals. The accuracy limits stem from a two year evaluation of meteorological signals from 93 wind farms.*

The results in Table 3.2 are to the advantage of nacelle computed or mounted wind data signals with a margin of approximately 19%. Moreover, the nacelle wind speed data signals win every partial measure with about the same margin.

Variable	Metric	Met Mast [%]	Nacelle Data [%]
WindSpeed	BIAS	62	79
WindSpeed	MAE	59	78
WindSpeed	COR	49	68
WindSpeed	ALL	47	66
WindDirection	BIAS	33	50
WindDirection	MAE	13	26
WindDirection	COR	33	52
WindDirection	ALL	11	24
AirTemp	BIAS	46	56
AirTemp	MAE	46	56
AirTemp	COR	46	62
AirTemp	ALL	37	50
AirPressure	BIAS	64	70
AirPressure	MAE	65	70
AirPressure	COR	54	74
AirPressure	ALL	50	69

Table 3.2: *Percentages of average accepted met data signals for met masts and nacelle wind farms for three metrics, BIAS < MAE and Correlation. The counting implied that wind farms succeeded on all three metrics.*

3.2 Analysis of four years of wind speed data for 93 wind farms

The objective of this section is to show the accuracy of the on-site wind speed data in more detail and over a longer time period, covering 4 years instead of 2 years.

We have developed a data validation technique which provides an overview and gives detail without disclosing confidential information on individual wind farms. The technique highlights the number of wind farms providing data of different quality levels over the 47 month time period. This technique allows for the examination of a subgroup of wind farms and highlight their characteristics with respect to quality.

We will compute the available active power generation (AvailActivePower) with the same method from two different wind speeds. Note that we used the available active power generation and not the net to grid generated MW to avoid issues in periods of dispatch or curtailment signals from the National Control Centre (NCC).

With the on-site measured wind speed we will compute AvailActivePower MW and with the forecasted wind speed we will compute AvailActivePower F. Both will be calibrated individually but otherwise the methodology is the same. The MAE forecast error range is normally from 6-16% depending on the wind farm, but with monthly variations that go even wider.

In case of a high error of the forecast, which can be due to one or two events on a particular wind farm, there is more potential for improvement when using the measured wind speed. In case of a forecast error of 16% it should be well possible for the on-site data to reach an MAE forecast error of 6% and therefore an improvement of 10%. Therefore, we defined an expected upper target for improvement of 10%. In periods where the forecast error is down at 6%, it is not realistic to reach more than 3% additional improvement with on-site data. Therefore, we have defined a target range for MAE improvement between 3-10% of capacity. It is possible that the improvement can exceed 10% if the forecast has had abnormal higher errors at a particular wind farm. An example of a high error could be a full HSSD error, which for a shorter while could imply 100% error. This could cause the monthly error exceeding 16% and therefore lead to a higher than 10% improvement using on-site data. An improvement higher than 10% would only be expected for a few wind farms.

The expected pattern is that only a few wind farms will exceed 10% improvement every so often. This is not negative if they exceed, but it is not realistic to achieve more than 10% improvement for a sustained period and therefore we set this as the upper target for improvement.

An improvement below 3% is a sign that the measured data should improve, but any value above 0 is an improvement over the forecast.

Up to 47 months of data for up to 93 wind farms have been used to generate the percentile figures of the improvement shown in Figures 3.6 - 3.11. For every month the available wind farms are used to compute the monthly percentile distribution of the MAE (forecasted wind speed) - MAE (measured wind speed)

Towards the end of the 4 years there is approximately 9 wind farms in each colour band in the figures, including all the wind farms. The “met mast measured” group is the smallest group with only two wind farms per colour band. Because of the increasing number of wind farms providing data, the later years are more robust than the first few years.

There are six figures showing the result of the investigation:

- 93 wind farms (Figure 3.6)
- 42 wind farms with nacelle data signals (Figure 3.7)
- 22 wind farm with mast data signals (Figure 3.8)
- 29 ENERCON wind farms (Figure 3.9)
- Nacelle data signal submitting wind farms prior to 2010 (Figure 3.11)
- Nacelle data signal submitting wind farms post 2010 (Figure 3.10)

Note that for the last two figures there were more wind farms included than in Figures 3.7 and 3.8 together, because there are 27 unknown sources not shown separately.

Note also that all six figures show 9 percentiles P10-P90 computed from the 93 wind farms at the end of the period of 4 years, where there are 2 times 4 colours above and below the yellow coloured area which represents P50. The black dotted lines indicate the target forecast, i.e. the forecast, when all wind farms would report wind speed with sufficient quality.

All 93 wind farms in one figure

The first result shown in figure 3.6 displays the MAE improvement for all 93 wind farms.

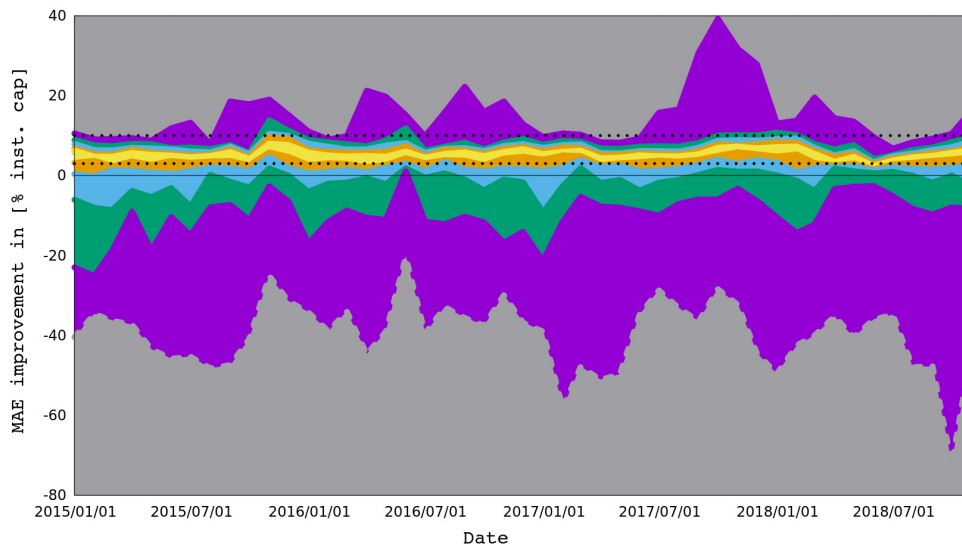


Figure 3.6: MAE improvement shown with 9 percentiles P10-P90 for forecasts using on-site measured wind speed to compute power generation in comparison to forecasted wind speed. The black dotted lines indicate the target forecast.

The 3.6 percentile figure is characterised by a rather consistent lower green band of wind farms just below zero. This means that their wind speeds cannot compete in accuracy with the forecasted wind speeds. These wind farms can be characterised by having frequent outages (e.g. constant values) in their delivery or poorly calibrated instrumentation.

The lower blue band lies around zero, but never reaches up above the expected 3% band. This band would be typical for wind farms providing constant data or poorly maintained instrumentation. The lower magenta band covers a wider band, because it spawns over the 10% providing the poorest quality of data. There are some width changes along the way, but the overall trend is that there are always 10% of the wind farms providing data of quality which is not useful.

The blue band values are always positive, so they enhance the forecast opposite to the two lower bands.

The two dotted lines represent the target range for the improvement over the forecast (3%-10%). There is mostly 6 colour bands within that range starting with P30 ending with P90 expressing that 60% of the wind farms hit the target area.

For real time data of moderate importance this fraction is about what can be expected and the forecasting system would function well, if there were 60% of all wind farms providing high quality data signals. Unfortunately, it is 60% of 25% of the wind farms, which is in fact 15% of wind farms. One can argue that it is a higher percentage on capacity, but the wind farms providing data of sufficient quality are not spread out well geographically. Therefore the effective band of good data corresponds to about 15% of the total. This number will vary from month to month depending on which wind farms have short and long outages.

There is a degradation in the latter half of the year, because the yellow and orange band tie close to the 3% band whereas these bands were closer to the centre of the target range. This period was characterised by several late stage hurricanes approaching Ireland with westerly winds causing HSSD events.

3.2.1 Analysis of Nacelle Data Signals

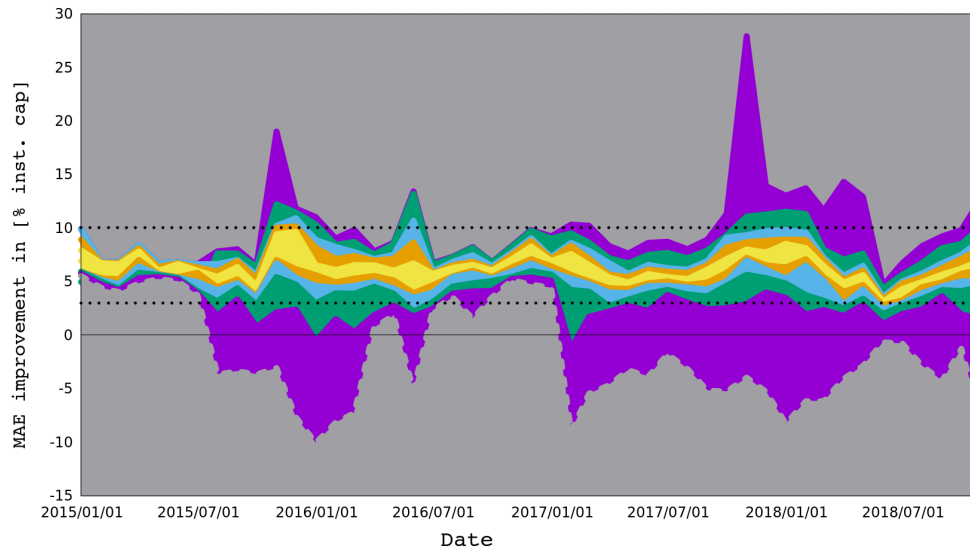


Figure 3.7: MAE improvement shown with 9 percentiles P10-P90 for forecasts using on-site measured wind speed to compute power generation of 42 wind farms known to submit nacelle wind speed. The black dotted lines indicate the target forecast.

Figure 3.7 has the highest percentage of data within the target range. There are 42 wind farms with a confirmed nacelle source for the submission of met data signals. The fraction of data under the 3% line is just above 20%, indicated by 2 colour bands (here green and purple). For 42 wind farms this corresponds to approximately 8 or 9 wind farms. That means approx. 34 nacelle wind farms actually meet the target sustainable. Note, also the high positive value of around 27% improvement in Figure 3.7. Such an improvement is the result of an outage at the wind farm, where the wind speed signals also go to zero independent of the true wind conditions. Outages are unknown to the forecasting system and because the wind speed and the power output are consistent, it cannot be filtered out as incorrect data. The consequence is that the forecasted wind is counted with a large error that generates significant negative impact on the statistical results. The overall observation that can be drawn from Figure 3.7 is a slight degradation in the quality of data signal at the beginning of 2018 (see purple areas below zero, meaning that the data is not useful) that improves towards the end of 2018 again.

3.2.2 Analysis of Meteorological Mast Data Signals

On Figure 3.8 we can count 60% of the 22 wind farms inside or above the target range with a similar quality pattern in 2018 as in Figure 3.7. We have seen this trend from nacelle data signals and also met mast signals and conclude that it is due to the dryer summer in 2018 with more easterly wind. The forecast is relatively better in this period, leaving less improvement potential from on-site data usage. There is slightly more variation of the central colour bands compared to the nacelle data, but this can be due to the lower number of met mast wind farms (22 compared to 42 nacelle wind farms). The fraction of data under zero follows Figure 3.6

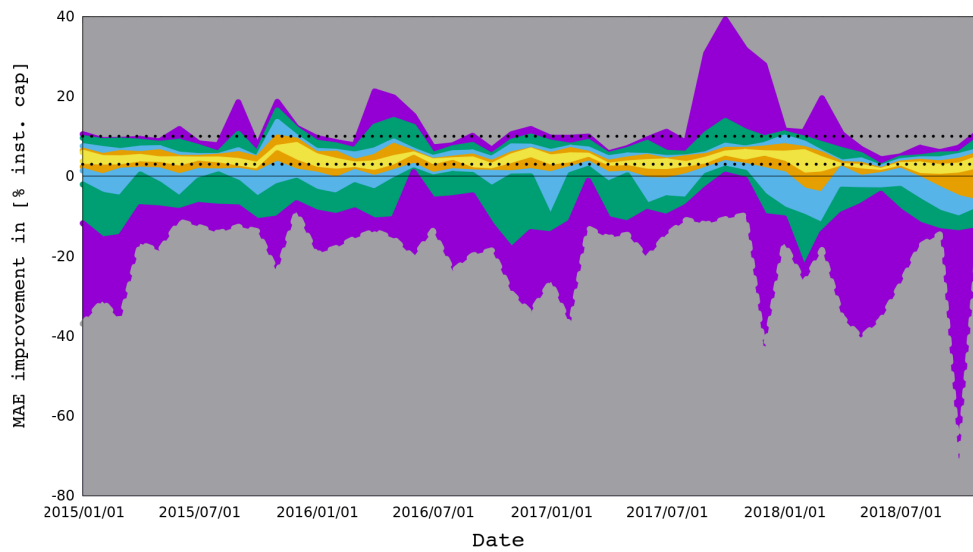


Figure 3.8: MAE improvement shown with 9 percentiles P10-P90 for forecasts using on-site measured wind speed to compute power generation of 22 wind farms known to submit met mast wind speed data signal. The black dotted lines indicate the target forecast.

3.2.3 Analysis of signals from ENERCON wind farms

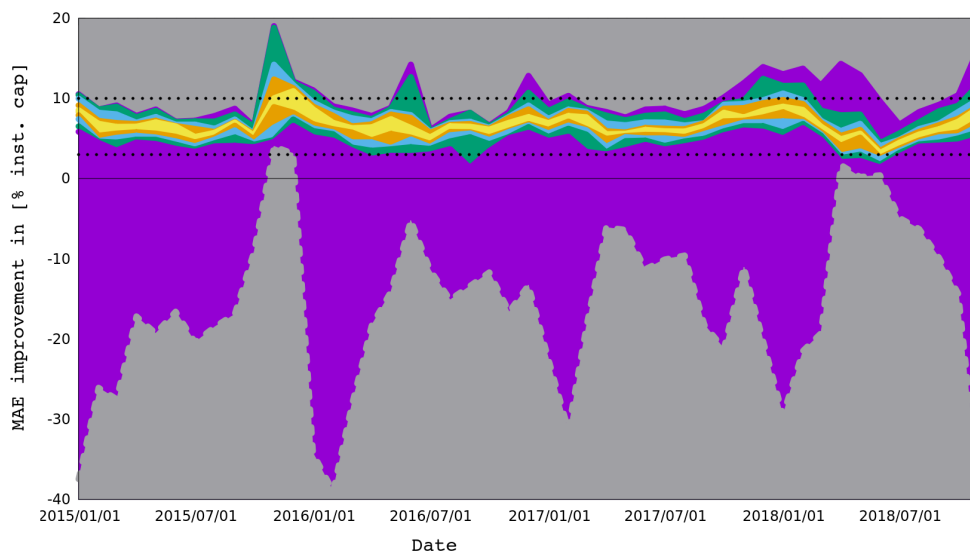


Figure 3.9: MAE improvement shown with 9 percentiles P10-P90 for forecasts using on-site measured wind speed to compute power generation of 29 wind farms with ENERCON turbines.

ENERCON has delivered wind turbines to 29 wind farms in Ireland and is the manufacturer with the highest share. The ENERCON technology deviates from other manufacturers. Therefore, it has been considered relevant to look at ENERCON wind farms separately.

The Figure 3.9 of ENERCON wind farms resembles the figure showing all wind farms delivering from the nacelle (Figure 3.7). There are 7 wind farms, where the source of met data signal is unknown and 3 wind farms, where the source of the met data is confirmed to come from a met mast site.

More detailed analysis reveals that the poor wind farms are among the 7 unknown (see purple band with negative improvement, i.e. below zero). We do not know, if they deliver data signals from a met mast, through blade pressure nacelle computations or cup anemometer signals at the nacelle. The graph indicates that ENERCON has had focus on providing accurate and consistent nacelle data signals. We are however not able to show why some ENERCON wind farms fail to do so.

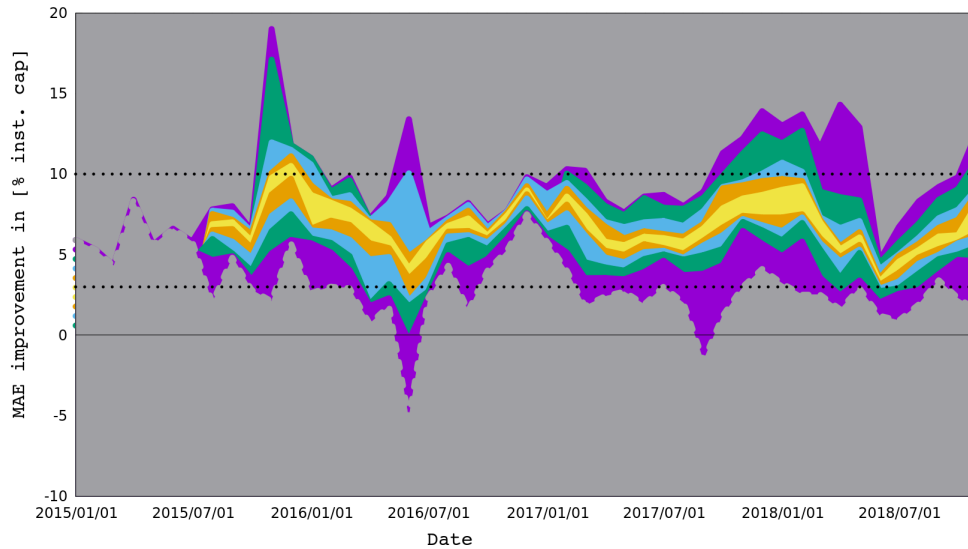


Figure 3.10: *MAE improvement shown with 9 percentiles P10-P90 for forecasts using onsite measured wind speed to compute power generation from ENERCON wind farms being grid connected post 2010.*

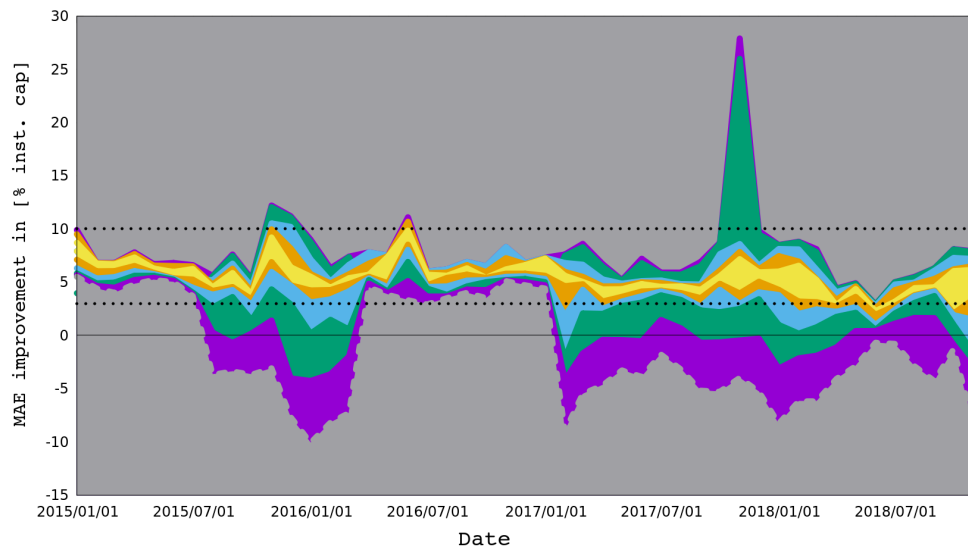


Figure 3.11: *MAE improvement shown with 9 percentiles P10-P90 for forecasts using on-site measured wind speed to compute power generation from ENERCON wind farms being grid connected prior to 2010.*

The two figures (3.10 and 3.11) show ENERCON wind farms with nacelle sources of met data signals separated by connection year 2010. There are only 70% of these wind farms that provide reliable wind speed data signals. Figure 3.10 show that the newer ENERCON farms are very reliable and Figure 3.11 shows that the older wind farms, connected prior to 2010 have a more variable performance, which is more comparable to the average of all wind farms.

3.2.4 Result Summary

In our analysis the accepted data signals from the nacelle show a better fit of the met signals to the power production compared to the data signals from met masts. Among the nacelle sourced met signals, ENERCON wind farms built after 2010 provide the most reliable nacelle sourced met data. The nacelle sourced met data signal from wind farms being grid connected prior to 2010 show a higher percentage of data quality below the target range. The better fit of accepted nacelle data has been found due to the calibration of the signals to fit the wind turbine's and/or wind farm's power curve. The signal from met masts are on the other hand independent measurements.

As discussed in Section 3.2.1 and 3.2.2, both signals are important and equally valid for the forecasting process as long as the signals reach the accuracy limits set in Section 3.1.4.

If we look at the wind farms not providing data that have been grid connected prior to 2010 with an installed capacity greater than 15 MW, we find 7 wind farms with a total installed capacity of 160 MW. These may or may not be able to qualify for the suggested accuracy. From the current submitted data signals, 20% of wind farms do not reach the expected and required accuracy. This corresponds to approximately 32 MW not reaching the 3-10% accuracy target. Using a 10 MW limit we find 250 MW in this category, corresponding to 50 MW of capacity that are unable to meet the target.

To summarise, the validation procedure allows for the examination of the wind farm met signal data in an anonymous form suitable to keep overview of the data quality. The graphs contain detailed information about how much capacity is not performing well. Temporary outages provide spikes in the data. While a forecasting system must be fault tolerant for blacklisting such data, it depends on the type of spike whether or not it is distinguishable from realistic data. The graphs illustrate that such extreme errors occur in individual months, often after periods of higher reliability. This indicates that this is due to a weather dependency.

Going forward, our results suggest that it is feasible to allow nacelle sourced met data for the provision of wind farm met data, if it is quality checked by the suggested or an equivalent method. The results from the analysis indicate that this will increase the number of on-site wind speed data and EirGrid can expect a higher overall quality of met signals.

3.3 High Speed Shutdown

In the most populated jurisdictions of the world, wind speeds around 25m/s are a rare phenomenon. Such wind speeds occur maybe at the coast or in mountainous areas, but very rarely cover a large portion of a given jurisdiction.

Practically all wind farms produce full generation, maybe limited by their maximum export capacity, when wind speeds reach approximately 15m/s until the wind farms HSSD set point or range kick in. Thus, from a power measurement perspective, it is not possible to calibrate forecasts against HSSD signals from a wind farm with generation data in the wind speed range below the HSSD, i.e. 20-25m/s. There is no visible sign in advance of a HSSD event in the time averaged power generation signal from a wind farm. Some kind of wind speed signal is required for HSSD forecasting.

In the following we will provide some considerations of this situation and the importance of met data to mitigate system operation issues due to HSSD in Ireland.

3.3.1 High Speed Shutdown considerations in Ireland

For Ireland the risks for high-speed shut down events are stronger than in most other jurisdictions with similar wind power penetration levels for a number of reasons:

- Ireland is located in the typical mid-latitude storm track zone
- There are 4 regions of Ireland with significant installed capacity
- There is no possibility to get continuous accurate wind measurements from the west of Ireland in a wind power relevant altitude due to Ireland's location on the western fringe of Europe
- The wind speed range just below HSSD occurs frequent
- In areas of complex terrain, scales of motion always exist in reality and are not resolvable by a forecast model
- The wind turbines react on time scales smaller than the weather forecast can forecast with good accuracy
- The learning from wind speed of the individual wind farm's HSSD characteristics is important, because there are manufacture differences
- The learning process from forecasted wind speeds would improve HSSD event forecasts, if there would be many similar events, but in reality these HSSD events are sparse
- The HSSD behaviour is software controlled and wind owners and/or manufacturers may reconfigure the settings regarding how a wind turbine shall switch off

The HSSD forecast process can therefore only use the locally measured wind speeds around 25m/s to learn the HSSD behaviour of the wind farm. Taking this approach, the learning process should be fairly accurate, even if there are only few HSSD events. The fine tuning from forecast to wind speed can be carried out on the 20-25m/s range, which occurs more frequently. As a consequence, the forecasted wind speeds from 25-30m/s can be used for HSSD forecasting.

If no reliable on-site wind speeds are available, then forecasted wind speeds will be paired with the HSSD signal from the wind farm. Given that it is normal to expect randomly varying errors of 1-2m/s of the forecast, this is not accurate enough. The error of a measured on-site wind speed may be on the same magnitude, but it should not be randomly varying and therefore be more suitable for creating the power curve between 25-30m/s.

The HSSD challenge in EirGrid and SONI is significant in that the wind resource in Ireland is better than in most other jurisdictions with major penetration levels. For this reason and the fact that Ireland is an island grid with limited interconnections, it is not unreasonable that there is a stronger obligation on the reliability of meteorological measurements than in other jurisdictions. Newer larger wind farms may also have better opportunities to provide detailed reports from the wind farm with more information than older wind farms (> 10years). Therefore, it would be natural that the requirements to wind farms with respect to reliability must be increasing with advanced technology for wind speed computations at the turbines and a backward compatibility is often not a possible requirement.

3.3.2 High Speed Shut Down Validation

The HSSD analysis has been limited to the wind farms that provided data of high quality. The wind farms are divided into 3 groups:

- data from nacelle instruments
- data from met mast instruments
- unknown data sources

In the following, we only considered data, where the HSSD signal exceeded 1%. We looked at the change of values over two time stamps within 15 min intervals. We verified the data with correlations of changes in wind speed, HSSD and AvailActivePower and focused on the consistency of changes over 15 minutes. The results are summarised in Table 3.3.

At the outset of the test, our assumption was that there must exist a near perfect consistency with a correlation of -1 or 1 in the data from wind farms providing high quality data. The reality showed considerable noise in the data, which is a result of the available data being sampled as 15 minute snapshots instead of averages. This effect and the spatial smoothing effects across each wind farm reduced the correlation significantly.

The results show highest correlations on all tests for nacelle sourced data. However, this result has to be taken with care: it is rather an indication for ENERCON providing the most consistent data around HSSD events, as the majority of nacelle sourced data signals are ENERCON turbines. The correlation for this group of data reached HSSD and AvailActivePower (column 5) of -0.87. These two time series should ideally correlate with -1 for all wind farms. The fact that they do not correlate with -1 suggests that wind turbines are not stable nor predictable around the HSSD set point and higher wind speeds or that there is a lack of effort to produce correct data in this range by the wind farm SCADA system. It should also be noted that for the high quality nacelle data, all three time series (wind speed, power generation and HSSD) are controlled by the turbine manufacturer who is maximising the consistency of the data. For example, the column named “correlation (HSSD,pwr)” does not use nor rely on wind speeds, but on a computation carried out by taking other means of observations on the turbine into account. Table 3.3 also shows that We detected more HSSD events in the data from met masts or unknown measurement types than for nacelle sourced data, most likely because ENERCON wind turbines are over-represented in the nacelle group and reach HSSD at a higher wind speed than what was observed at wind farms with met masts or an unknown source.

Measurement source	Number of wind farms	Number of HSSD events	correlation (wind,HSSD)	correlation (HSSD,pwr)	correlation (wind,pwr)
met mast	7	70	0.34	-0.66	-0.42
unknown	9	73	0.25	-0.49	-0.15
nacelle	16	44	0.35	-0.87	-0.35

Table 3.3: *HSSD correlation results for wind to HSSD, power generation to HSSD and wind to AvailActivePower, averaged by source. The results only consider HSSD events. The last column shows for this reason strong anti-correlation.*

The wind speed to HSSD correlation (column 4) is practically even between nacelle sourced data and met mast sourced data in terms of wind against HSSD correlation. The result is less clear than for HSSD against AvailActivePower correlation, because the wind speed can increase in stable conditions without increasing the HSSD risk.

In Table 3.3 we found the same absolute correlation result for the correlation of wind against HSSD (correlation(wind,HSSD)) and wind against active power (correlation(wind,pwr)). This confirms that data is more consistent when it is handled by one party. Because, the met mast sourced data result is a point measurement and the nacelle sourced data result is a wind farm average, we cannot expect the same correlations on met mast sourced data as on nacelle sourced data. However, the important correlation from wind speed to AvailActivePower (correlation (wind, pwr)) is stronger for met mast sourced wind speeds than for nacelle sourced data.

For the met mast sourced data we found a stronger correlation between wind speed and AvailActivePower (correlation (wind, pwr)) than for the nacelle sourced wind speed data. This could be interpreted as an indication that the $|0.35|$ of the nacelle data correlation is a consequence of inaccurate wind speeds around the HSSD set point. In fact, this result shows a weakness of nacelle sourced wind speed data signals. Once a wind turbine has stopped generating power, the blades will be fully pitched.

The wind speed can no longer be derived from the pressure on the blades, but has to be derived from the anemometer mounted on the nacelle. The shift of recording technique is most likely also the reason for the fact that the nacelle sourced data is worse than the met mast data in the wind to power correlation verification.

It is difficult to calculate the wind speed in such circumstances and conditions. The downstream turbines will likely generate power and provide a blade pressure based wind speed, whereas the upstream turbines will report only wind speed from the anemometers at the nacelle. The central software solution will have to correct the wind speed reports at the wind turbine to ensure that the cup anemometer based wind speed is consistent with the previously computed values. These corrections are not trivial and can lead to spurious results, whereas met mast measured wind speeds are well defined signals.

With one minute time resolution the gust factor would also be better estimated and the HSSD set point would be better explained. One minute data would strengthen the position of met mast sourced data over nacelle sourced data, because nacelle winds do not suffer from the 1 minute snapshot process that met mast wind speeds do in the current operational setup.

In the next Section 3.4, we show how these uncertainties on HSSD can be circumvented by using one min resolution data in the forecast process to estimate gusts in the wind and at the same time also follow the changes of mean values every minute.

Comparison of nacelle versus met mast sourced wind speeds

The gain of nacelle sourced wind speeds versus met mast sourced wind speeds depends strongly on how consistent the wind signal is to the power curve and how the transition from blade pressure computed wind speed to cup anemometer measured wind speed is handled. On September 19, 2018 the so far strongest HSSD event has been observed. The event illustrated that many wind farm's nacelle sourced met data signal provision failed and went into providing constant data of some arbitrary value.

For some wind farms, the corrupted data delivery lasted much longer than the storm and the results became inconsistent on power generation, HSSD wind speeds and general wind speed for at least some of the nacelle sourced wind farms. This event indicated also that it is not wise to rely on nacelle wind speeds around and above HSSD wind speeds.

There is need for improvement and significantly more and important information available from met mast sourced data during HSSD events. The wind farm is often challenged by gusty winds. For this reason, the recording of the wind speed should ideally be independent and be accessible without the need of the wind farm software.

Conclusion of HSSD Validation

The 19th of September event illustrated that the nacelle wind farms, which normally have an excellent consistency between wind speed and power, failed to provide data of sufficient quality at the HSSD point, which is where data quality is most important from a grid security perspective.

It is therefore worth noting that (1) if the wind speed data signals fails above the HSSD level, there is only the weather forecast to predict when the wind farm will resume power generation and (2) there is no warning information from the wind farm in HSSD mode that can be extrapolated to other wind farms. As a consequence, poor reliability at HSSD is the major concern when allowing nacelle sourced wind speeds as an alternative to met masts.

3.4 Validation of one minute time resolution data

At the time of the study, the real time forecasting system exchanged one minute snapshots of wind farm data in 15 minute intervals. We identified that the lack of averaging of this process lead to a disadvantage for met mast sourced data in comparison to nacelle sourced data in the evaluation.

This is due to the met mast data being random values within a 15 min interval, which is a poor estimate of the wind speed in time and space across a wind farm. It also means that the met mast wind speed data signal is equivalent to a point signal whereas the nacelle wind speed can be considered an area signal.

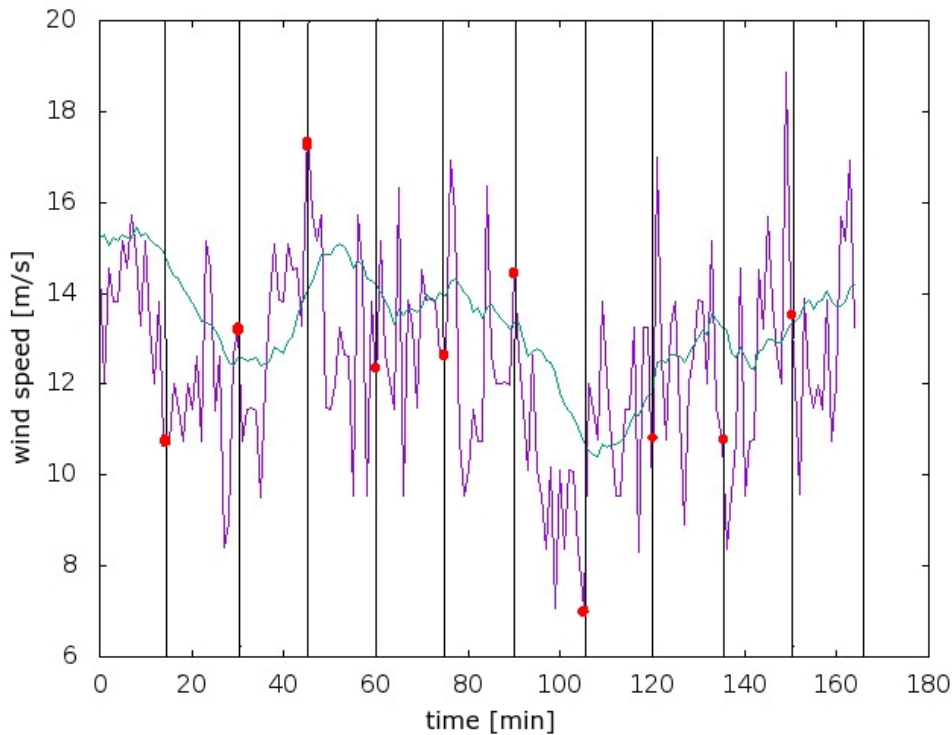


Figure 3.12: Illustration of wind speed measurement from a met mast over 3 hours with signals on 1 min sampling intervals (purple line), 15 min running averages (green line) and 15 min snapshots (red dots).

Figure 3.12 illustrates how one minute snapshots taken in 15 minute intervals (red dots) appear to oscillate around the running 15 minute average (green line) and how the one min wind speed averages vary in a noisy pattern due to turbulence and meso-scale weather. Similar variation exists in the used power data. This is common for both nacelle and mast sourced data. The met mast wind speed oscillations are out of sync with the power oscillations, because they show effectively an independent weather signal, whereas the nacelle data are in sync with the power production, because it is the same process calculating wind speed and power output. In order to quantify the impact of this difference and to verify our conclusions drawn in Section 3.3.2, we validated wind speed data signals from met masts in one minute time resolution and compared the results to selected wind farms providing nacelle sourced wind speed data signals over a period of 3 windy months with a couple of storm events.

3.4.1 Validation for selected wind farms supplying data from met masts

The validation of one minute data was carried out with all met mast sourced wind farms of sufficient quality and a selected list of nacelle wind farms for a period of 3 months, covering September, October and November 2018. The list of nacelle wind farms were selected from the top ranking of all nacelle sourced data with the only constraint that all major manufacturers should be represented in the list.

Source	BIAS	MAE	RMSE	CORR
mast	1.30	2.21	2.96	0.79
nacelle	1.75	2.20	2.94	0.78

Table 3.4: Accuracy of on-site wind speeds against the MSEPS ensemble mean forecasted wind speeds computed for 3 months for two selected groups of wind farms of equal size.

Source	Wind Speed	Sampling	BIAS	MAE	RMSE	BIAS	MAE	RMSE
met mast	measured	1min	-1.53	8.44	12.78	-1.44	4.08	5.50
met mast	measured	15min	-1.45	6.93	10.76	-1.36	3.25	4.43
met mast	forecast	10min	0.13	11.49	16.11	0.20	5.52	7.36
nacelle	measured	1min	-0.39	3.68	5.86	-0.38	1.83	2.62
nacelle	forecast	1min	0.90	12.79	17.26	0.96	6.31	8.3

Table 3.5: Verification of wind speed signals converted to wind power with AvailActivePower measurements. The wind speed signals are from met masts with one minute sampling and 15 min averages and nacelle sourced wind speed. The first verification set of BIAS/MAE/RMSE is valid for the average of the selected wind farms. The second set is valid for the aggregation of the selected wind farms. The result of aggregated power generation is much lower because summation over wind farms cancel out some the errors.

With the running 15 minute mean (averaging the 1 min data over 15 minutes) we simulate something approximately equivalent to a one minute average over the wind turbines rotor area and thereby make the wind speed data more consistent with the power data.

Table 3.4 shows that there is no significant difference in accuracy of the wind speed from mast or nacelle sourced data against forecasted wind speed. This is consistent with our conclusions in Section 3.3.2 and expectations above, i.e. that the met mast sourced data was penalised in the validation due to the type of data sampling.

In table 3.5 we present the verification in 5 rows of measured and forecasted met mast and nacelle sourced data and their forecasts, respectively.

Analysis of the one minute data validation

In our analysis, we first focus on the two rows in table 3.5, where the wind speed is taken from the forecast. The met mast group has 1.3% lower MAE than nacelle. We conclude from this that the conditions are the same for the two data sources.

For measured met mast sourced wind speed it should be noted that the wind speed with the correct 15 minute sampling is significantly better than the one with 1 minute sampling. A 20% improvement of the result is evidence that there is significant variability on the one minute time scale in the data and that in a forecast application, the amplitude of the 15 minute average is considerably smaller and much easier to use and interpret.

However, the improved result still shows a significantly higher error in average than the nacelle sourced wind speed. The ratio between the average error and the aggregated error is close to a factor of two in each row of the table. This means that the errors on the individual wind farms are 50% random and uncorrelated between wind farms.

It was surprising to find that 50% of the wind farm's specific error remains uncorrelated as the accuracy increases. Thus, what is a random error depends on the accuracy of the methodology.

The process is so sensitive that there still is a random error left in the per wind farm result. The nacelle wind speed data obviously contains some significant wind farm specific detail of the wind speed, which is not captured by the met mast data signals. This could be the horizontal and/or vertical variation across the wind farm. Similarly, the 15 min average of the met mast sourced data signals contain information, which the one minute sample does not contain. Also, the met mast sourced wind speed contains some significant details, which is not contained in the forecast. These are however small differences in the phase of meso-scale weather and vertical wind profiles that are uncorrelated between wind farms.

The different levels of detail of the wind field demonstrates that there is a cascade of errors with different scales and degrees of locality. The fact that the measured nacelle wind has almost half of the error of the met mast measured wind shows that the nacelle wind describes the power generation better than the met mast wind.

The confidential nature of the computation of the nacelle sourced wind speed is also an indication of an artificial quantity to some extent, because it is constructed to fit the power curve of the wind turbine, which the turbine is supposed to follow. In that sense, this type of nacelle sourced wind speed can be understood as a virtual localised wind speed inclusive internal and external wake effects. Additionally, it can be expected that the vertical average over the rotor area is taken into account and that the signal includes the impact of other wind turbines, also if such effects are limited to a small fraction of the wind farm. All these effects can be seen as small perturbations to the wind speed recorded on a met mast.

Conclusion of the one minute data validation

The question on the accuracy of nacelle sourced wind speed versus met mast sourced wind speed remains unanswered. Which one of the measurements is more accurate depends on the detailed purpose of measuring the wind speed. The mast provides a clean signal of how the wind speed at the location evolves. The nacelle sourced wind instead provides a signal of how the power generation evolves, normalised back to a wind speed coordinate system via some confidential methodologies. Each manufacture can to some extent choose to define the nacelle wind speed differently and individually. Apparently, the difference between the mast sourced wind speed and nacelle sourced wind speed is small compared to the differences to the forecast. Both contain the localised effect much more accurately than the forecast.

Nevertheless, the results also indicate that forecast, nacelle and met mast have similar accuracy of the large-scale effects. The nacelle sourced wind contains the wind farm specific localised effects and the met mast sourced wind contains some local effect on the wind, but not on the wind farm as a whole. In other words, the met mast provides a wind farm independent signal of the local weather conditions, while the nacelle wind is a wind farm dependent signal indicating the local effect of the weather on the turbines.

3.5 Discussion of Data Analysis Results

Our results indicate a similar wind speed forecast error statistics for met mast sites and nacelle sites when using the one minute resolution data.

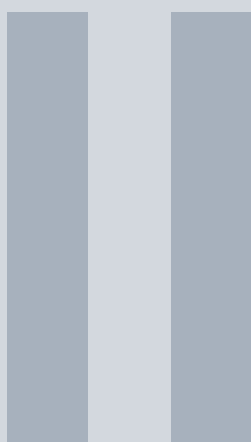
The met mast sourced wind is superior to nacelle sourced wind when evaluated on HSSD set points. However, on all other verification results nacelle sourced data is either better or equally good as met mast sourced data signals. When evaluated on the converted wind to power generation, nacelle sourced data is superior to met mast sourced data. The verification results hence demonstrate the strength in the power generation forecast when using nacelle sourced wind over met mast sourced wind.

We had however no possibility to compare met mast and nacelle sourced data on the same wind farm, because we received either nacelle sourced wind or met mast sourced wind. And, just a few kilometre distance between two wind farms and the time series are too far off that a comparison is meaningful.

The main scope of the report was to investigate, whether or not the already existing nacelle sourced provision of wind speed can be accepted. Given that the analysis did not negate the accuracy of nacelle sourced wind in normal weather conditions on the wind speed and on power in any wind speed, it is difficult not to accept nacelle wind speed as an acceptable met data signal.

There are still three potential risks:

1. Limited access to the provision of data from wind farms
For the study's validation and the real-time feed it is considered a limitation that only one value is available per wind farm. This limits the forecaster to activate more advanced methods to handle the HSSD risk and ramping in extreme events. Most of the conclusions had to be drawn from averages over many wind farms separated by their data source.
2. Manufacturer control of the wind speed
The manufacture control adds uncertainty to the signal. However, we also know that this is a way of ensuring that the wind speed is aligned with the power generation. The risk is that it is possibly too much aligned with the wind farm and that we cannot use the nacelle reported wind speed to represent other wind farms.
3. Poor performance of the nacelle sourced wind signals near the HSSD point
In the HSSD events, the met mast wind speeds outperform the nacelle wind speed even though they are independent. One would expect more consistency between the reported nacelle wind speed and power generation, than what an independent mast can report, because the decision making of the wind farm should be based on the wind speed that is available according to the specifications. We can derive that the nacelle wind speed is chaotic around the HSSD. It is not a topic which has received attention from manufacturers except ENERCON who appear to be consistently strongest on nacelle wind speeds. The nacelle wind speed is a software defined wind speed, which is defined as long as the wind turbine generates power, but loses accuracy, if the turbines are not generating power. The HSSD wind speed range is a risk factor, because the wind farm manufacture can choose to not give priority to the topic as most jurisdictions do not experience frequent HSSD wind speeds. Stronger requirements for approval of turbine models in Ireland could be required to ensure the topic gets priority.



Part Two

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4. Data Requirements

In this section we will discuss the technical requirements for meteorological data for the forecasting process taking the results of the previous sections into consideration.

4.1 Data requirements for 20 year old wind farms

For the future design of wind power production incentives it shall be noted that there will be significant pressure on market prices the more correlated wind generation is across Ireland, the UK, the North sea, the Netherlands and Denmark. This will also apply to Ireland in periods of high correlation, as it can be expected that there will be more interconnection between Ireland and the mainland.

This can lead to wind farms being awarded on market terms to gradually stop generation when the market prices drop below 1 EUR cent. Wind farms of age > 20 years, which are currently 71MW will increase to 140MW in 2020. Oversupply from wind is most likely to occur during the Christmas holiday season, where the ratio between wind power generation and industry load is poorest. The 20 year rule will in 2020 be applicable for three 15MW farms and six wind farms between 5 and 11MW.

In this context it is worth noting that the market prices may not cover their marginal costs of operating anymore. This is what has happened in Denmark and Germany in recent years. Independent of any economic reasoning, the centralised forecasting solution needs to be able to forecast their output as long as they generate and feed in power to the grid. Therefore, data provision requirements need to be formalised as well for old wind farms.

The current SCADA feed contains only the MW value for these wind farms. Some of them also have outage signals. It is also important that they are configured to provide their available active power capability (AvailActivePower). Otherwise the forecasting system will have to make an assumption on the reason for low generation, i.e. whether low generation is due to low market prices, low wind farm availability or a forecast error.

As the volume of wind farms on market terms (without feed-in tariffs) increases in the following years this dilemma will increase, unless the wind farms provide more detailed data.

To privatise the handling of these small wind farms as has been done in Denmark and Germany will not help the forecasting, but it will generate a financial incentive for the wind farm to bid into the market with their marginal price and schedule their generation accordingly.

Given that at least three of the > 20 year old 15MW wind farms are likely to continue operation there is a certain relevance for the question regarding the allowance of nacelle generated wind in the future. How accurate nacelle sourced data would be at these three wind farms and what it will cost is an open question. They are all VESTAS wind farms (one NEG, which is now part of VESTAS). The following procedures and enhancements are recommended for all wind farms:

- Provision of available active power capability (AvailActivePower)
- Provision of unplanned outage signals

4.2 Future real time forecasting data requirements for met data signals

Ideal Met Mast Data Signals

From met masts the optimal solution would require that readings from multiple cup or sonic anemometers taken on 1-minute basis to evaluate the wind profile and gust factor of the wind and to generate a rolling 10-15 minute mean value. In this way, the trend of the wind speed can be identified. The optimal heights for the cup or sonic anemometers would be starting at 10m, 20m, 35m or max. height

Ideal Nacelle Data Signals

On nacelle sourced data the time resolution of the data signals would be sufficient in 5 minute mean values when it is delivered from the individual turbines. In that way, gradients in the wind speed across the wind farm can be identified and how much such gradients move. From a IT system operational perspective it would however be most sensible to agree on the same averaging for all and require a 1-minute averaging as well.

Impact on higher time resolution data for the ST forecast

The consistent averages of the wind speed and power measurements as rolling mean values will ensure that the ST forecast will gradually adapt to the changes. Especially, the current 1-minute snapshots of wind speeds delivered every 15 minutes is a problem for the forecasting system. A change to mean values on a 1-minute basis will ensure that the ST forecast will gradually adapt to the changes. The noise in the current 1-minute snapshot delivered every 15 minutes also triggers some noise in the forecast. A smoother ST forecast with smaller difference from forecast will also be easier to use in the control room for decision making.

Administrative requirements for change to a 1-minute data provision

A disadvantage of allowing diversity in the meteorological data from wind farms is the increased administrative costs. From current experience of the SCADA feed, it is estimated that the number of SCADA feeds to the forecast will increase by a factor 15 when going over to 1 minute time resolution and individual wind turbines.

This is a small change to the system as is in 2018, but with a considerable value to forecasting. Doing so will automatically communicate the detailed HSSD signal per wind farm to the forecasters, which will help them to keep track of changes of the HSSD set point per wind farm. The 15 minute snapshots from one measurement unit do not allow for this feature.

A system wide 1-minute resolution requirement is easier to maintain and is exploiting the existing data feeds from already compliant wind farms. The weak side of the uniform approach may be that over time more and more wind farms will opt for the nacelle sourced data. As a consequence there will be very limited information on the vertical wind profile of wind farms. Gusts cannot be detected and thereby, neither in stable nor unstable conditions. In stable conditions the vertical dependence can only be identified by comparing nearby wind farms at different altitudes.

Summary of the recommendations

1. 1-minute data sampling from multiple cup anemometer from met mast data signals
2. 1-minute data sampling from nacelle measured wind speed data due to IT-solution consistency

4.3 Discussion on height of Met Masts

With increasing heights of wind turbines, a strict requirement for met masts measuring at hub-height is no longer justifiable as a general rule. The argument that measurements have to be taken at hub-height level has a history from the time, where wind turbines were in the range of 35-50m. Taller wind turbines have longer blades and reach up in stronger wind. Most of the power generation is due to the wind speed of the upper range of the blades. The result is that a measurement taken at hub height is no longer sufficient to describe the power generation of these large wind turbines of >70m. There is no longer a cost-benefit ration that is justifiable for this requirement. Met masts of that height are too costly in comparison to the benefit over a met mast at lower height. Measuring the entire sweep area of modern wind turbines is a task for LiDAR (Light Detection and Ranging) solutions. This is also why LiDAR has in recent years been applied successfully in the planing of wind farms and incorporated in the IEC61400-12-1:2017 standard[?].

Met masts become relatively more expensive with increasing height. Maintenance costs and planning permission is another disadvantage. In flat terrain the hub-height measurement is turbine dependent. Therefore, accepting a height of 2/3 of hub height with a minimum of 35m for met masts would be in fact equally beneficial and much more cost efficient in facilitating met masts as an independent measurement at wind farms without compromising the added value for forecasting. Especially also at the older wind farms, where modern nacelle measurement computations are not feasible or possible.

From 1-minute data sampling, it is still possible to estimate the gust strength at higher altitudes and thereby also add value in the forecasting of the HSSD events. Especially, because the measurements are independent of the wind turbine software. Allowing for met masts of ca. 2/3 of hub height is going to increase diversity and ease the maintenance and therefore also the system reliability. If service and maintenance is not costly, the likelihood that it is carried out according to the anticipated requirements is much higher.

The acceptance of met masts of 2/3 of hub height with a minimum of 35m height will implicitly also limit the charges manufacturer could put on maintenance of nacelle sourced wind speeds under a delivery requirement. For many wind farms a met mast of 2/3 of hub height may in fact be a more feasible alternative with minimal space requirements. Met masts in that height also do not cause disturbing turbulence for the wind farms.

Summary of the recommendations

1. 1-minute data sampling for all met data signals
2. Lowering the met mast height requirement to 2/3 of hub height with a minimum of 35m (see also section 6.3 and MEASNET, 2016, pp. 9-10]

4.4 Recommended Practise for a Met Data Delivery Requirement policy

The main question for a delivery requirement on wind speed signal delivery is how outages on the wind farm may influence the meteorological data quality. The current standard seems to be that a wind farm can deliver data also during periods of zero availability, but most nacelle wind data signals are delivering zero wind speeds in such cases. There are stronger outage levels, where no data is being delivered or the last value is repeated.

During typical autumn conditions with moderate high mean wind speed and one or two storms per month, it seems sufficient to allow for one day of maintenance per month. So 98.5% of the data should be timely and valid. This requirement is easy to maintain in summer, but is more challenging in January and February, because storm events last longer and there are short time slots in between for maintenance. Moreover correlated errors occur at many wind farms, because the weather is more correlated in winter than in summer.

Shorter periods of daylight is a complication factor in winter time. Nevertheless, the winter is the period, where wind farms produce full load most frequently and over longer periods. HSSD events are most frequent in this period and the load is highest. Therefore, the reliability of the wind generation should also be at the highest level during winter conditions.

Of all winter characteristics, it is only the more correlated weather which could justify a reduced delivery requirement of 98% of the time. Most factors point to the winter being more important than summer. Therefore, it is best practise to keep the same percentage all year around. We suggest to implement a 98.5% delivery requirement as either a monthly or bi-monthly requirement. Thus, if there is no outage in the previous month, then a longer outages is allowed for the current month, but only one outage period of the previous month can be used for maintenance. So in total 22 hours are available for maintenance in any month, if there was no outage in the previous or following month.

This delivery requirement will require more staff for maintenance in the winter period, but the power generation is approximately double of the summer months. Therefore, the effectively stronger SLA requirement for winter conditions makes overall sense despite the tougher conditions for maintenance and higher risk of outages.

Mast data outages can be prevented by maintaining multiple anemometers on the mast and automated fail-over. For nacelle data signals at wind farm level there should be fail-over between the blade pressure based wind speed to the cup anemometers. Firmware/software upgrades should not be scheduled to take place during the winter, unless there are errors that need immediate repair. A strong HSSD event could lead to longer outages of the wind farm and there is currently no procedure to communicate that a wind farm is in outage several days ahead. Such a procedure should become a requirement along with the delivery requirement, so a wind farm operator can inform the TSO how long the wind farm is expected to stay in outage. In that way, SLA obligations can be lifted until the wind farm is scheduled to resume operation.

Operation of wind farms during winter can therefore be facilitated with some simple proactive steps to ensure the 98.5% level is sustained.

Summary of Recommendations

1. Delivery requirement: 98.5% of the time
2. Incorporation of announcements by operators on partial and non-partial non-scheduled and scheduled outages into the IT system

4.5 Future use of LiDAR

In the second phase of this study there has been no efforts made to examine LiDAR technology.

Common experience is that the LiDAR technology is suitable for dryer climates with lower wind speeds, or when data needs are not as critical in extreme events and in real-time as they are in Ireland.

The weaknesses of LiDAR at HSSD wind speeds and with strong precipitation is a crucial factor, because there are moments, where wind speeds are extremely important. Loss of data around the HSSD point is likely with current LiDAR techniques and can not be accepted. The International Energy Agency (IEA) Wind Task 32 workshop on LiDAR for minute-scale forecasting in June 2018 has concluded that these instruments physically are not capable of measuring with high accuracy in situation of strong gusts and high humidity or strong precipitation. The laser technology does not support accuracy under these conditions. A submitted publication by some of the workshop participants describes these issues in detail [Wüerth, 2019].

LiDAR solutions are at present not yet economically viable as permanent single installations due to a lack of operational experience in real-time electrical grid environments, where no post-processing can take place. In meteorological real-time applications LiDARs are one of many instruments which have much lower individual accuracy requirements. Given that we recommend a delivery requirement of 98.5% delivery of correct data, today's LiDAR technology will not be able to provide such a high percentage in Ireland. Except maybe in summer time, where storms are unlikely, it is unrealistic that a LiDAR can qualify under the recommended delivery requirement as an alternative to met masts. The cost of a long-term service contract for the LiDAR technology can also be expected to be significantly higher compared to met masts or nacelle sourced instruments, because it is not yet a long-term proven technology for real-time applications.

LiDAR technology can however in the future be useful to verify the correctness of wind speeds from wind farms in case of poor accuracy of the wind speeds of a wind farm. This is the kind of application the LiDAR technology is designed for. In that way, LiDARs may play a major role in the future in Ireland, but not as a permanent installation, because this technology will not be able to reach a delivery requirement needed for the recommended reliability. The study has revealed that there is a wind farm in NI providing nacelle data, where such an independent test seems to be the only way to prove or disprove whether the provided wind speed describes the wind speed or the power generation.

In case of doubt or for a qualification process of instruments, a LiDAR is a good option to use. With an effective implementation of a delivery requirement, a verification of the correctness of on-site wind speeds may have to be verified for a period of time by an independent instrument either prior or in cases of doubt. Here, the IEC61400-12-1:2017 [IEC, 2017] Annex I standard may serve as a guide for the qualification process.

A LiDAR system could only achieve the reliability in combination with another source such as a (LiDAR) drone specially developed to fly in strong wind at a fixed position. This is a new technology that requires experience and testing and shall be here only mentioned, because we are aware of technology advances that may come along with time. Our recommendation is to leave an open door for new technologies when setting up new grid code requirements. New technology should always get the chance to get tested and verified with a real-time test period. If such new technology is also useful for the wind farm operation, cost may not be the only decision factor.

Summary of Recommendations

1. LiDARs are at present not an alternative to met masts, as they will most likely not be able to comply to a delivery requirement of 98.5% in Ireland
2. LiDARs may be used to prove correctness of met mast or nacelle sourced data signals and as a calibration method according to IEC61400-12-1:2017
3. Technology advances with remote sensing instruments (LiDAR, SODAR, RADAR) should be allowed to get considered as alternative measurement type e.g. in combination with other instruments (e.g. drones) through real-time test periods.



5. Analysis of alternative met data information

5.1 Wind measurements from a LiDAR

In order to evaluate alternative measurement data from a LiDAR, we received a data set of 3 months from one wind farm from April to June 2015. The data were averages over 10min intervals. Wind speeds at 11 heights above ground have been available for the verification. Table 19 shows the mean of the measurements and the failure rate of the instrument. This test was carried out in order to understand the pattern in which the instrument has difficulties in Ireland to provide reliable data in real-time. This test has to be understood in that context rather than to show the weakness of the instrument. Like for the validation of met masts and nacelle wind speeds, it takes a considerable amount of tests to objectively show that the data does not contain some accuracy issues in particular wind speed ranges. Plain standard verification can only show whether or not the data is reasonably accurate. For nacelle and met mast sourced met data, we analysed 4 years of data. A similar amount of data would be required to justify a solid positive or negative statement about LiDAR data. Nevertheless, the data was used to carry out a verification with the EPS Mean of the 75 member MSEPS Ensemble System at the 4 model levels used in Ireland for forecasting purposes. In a real-time environment, this could be optimised with either interpolation of model levels to the measured levels of the instrument or adjustment of the instrument to measure at the approximate model level heights.

The low BIAS at the top level shows that the instrument correlates well with that model level. It can be seen that in the heights 90m and 100m there are 18% of data missing and the best data coverage is between 10m and 40m. The latter result is consistent with what we see in literature [e.g. Burin, 2014, Deutsche Windguard, 2013]. The missing availability of 10% in heights above 50m would have to be examined in more detail in order to draw a conclusion. However, one of the observations we made in the data is that if the signals stall, they stall over most levels, sometimes with a phase shift of 2-3 time intervals. We also observed that often missing data signals are associated with precipitation and/or high wind speeds. This is not always the case, but if there are outages, mostly there are high wind speeds present or have just been there, which is consistent with some of the experience in literature [Lang, 2011, Courtney et al, 2012, Nakafuji, 2012].

LiDAR data	% missing Data	MEAN [m/s]	BIAS [%inst. cap]	MAE [%inst. cap]	RMSE [%inst. cap]	height agl.[m]
Wind Speed (m/s) at 179m	13.4	8.6	0.01	1.42	1.86	179
Wind Speed (m/s) at 155m	13.3	8.4	-	-	-	
Wind Speed (m/s) at 127m	14.8	8.1	-	-	-	
Wind Speed (m/s) at 99m	18.4	7.6	0.41	1.35	1.74	98
Wind Speed (m/s) at 90m	18.3	7.4	-	-	-	
Wind Speed (m/s) at 79m	17.4	7.2	-	-	-	
Wind Speed (m/s) at 69m	15.8	7.0	-	-	-	
Wind Speed (m/s) at 49m	10.5	6.6	-	-	-	
Wind Speed (m/s) at 38m	6.0	6.4	0.44	1.22	1.55	38
Wind Speed (m/s) at 29m	4.0	6.2	-	-	-	
Wind Speed (m/s) at 10m	1.7	5.3	-0.63	1.11	1.44	10

Table 5.1: Statistical results of LiDAR data at IE017a with measured and forecasted wind for 3 months from April – June 2015 .

For resource assessments this is not an issue, but for real-time operations, where data signals are most important in active weather situations with high wind speeds and sometimes strong precipitation, allowance of a LiDAR in Ireland as an alternative to a met mast would require a longer pilot project to identify whether the LiDAR can be calibrated to provide the required reliability of signals.

As of now, we can say that our analysis is consistent with other studies in the literature, where LiDARs and SODARs are mostly used for measurement campaigns and resource assessments as one of many measurement signals in a large scale data analysis [Kelly, 2014, Bradley, Binguol, 2012, 2008, NREL, 2007]. In these measurement campaigns reported in the literature, we also see the result after software processing of high time resolution signals with the knowledge about what happened in the minutes after the measurement was supposed to be made. The historic remote sensing data are therefore likely to be better than those provided in real-time. The results we see would most likely not be equivalent to what would be delivered in real-time, because there would be errors in the data, which could be more or less difficult to filter out in 5 or 10 minute sampled data on the forecaster side. It will also be difficult to keep the users of data informed about software updates of the signal processing software on the remote sensing device and regenerate historic time series after every software update.

The cost, difficulties and accuracy limits of remote sensing are in this case easily underestimated while comparing with known technology with less complexity. For real-time forecasting for system operation that needs reliable signals at all times and at all wind speed ranges, and especially in extreme events and in dispatch situations, these instruments seem to not be mature enough yet.

5.2 Alternatives to met data collection at the wind farms

In Section 1.5, we have described and examined solutions to provide meteorological measurements directly at the wind farms. In the following, we summarise and comment on other potentially available data sources for wind power forecasting:

- Use of SYNOP data: the density, altitude (10m) and reporting interval (3h) are unsuitable for wind power forecasting purposes
- Selection of strategic positions of remote sensing westward of wind farm clusters: this could add value on forecast hour 1 and 2
- Nacelle data from the corners of each wind farm: lacks quality during dispatch

- Use of remote sensing at strategic locations far west: This will mainly add value in storm events and hardly improve 0-1 hour forecast
- RADAR signals: useful, if they can be inverted with a level of detail, which is sufficient to increase forecast accuracy. Even though frequently available, the value of this data is uncertain, because of challenges in their application for wind power. The potential lead time could be 1-3 hours.
- Remove the obligation to provide data: this will lead to lower forecast quality and less situational awareness

Our conclusion is that the on-site mast data is optimal for short-term (up to 12h) and ultra-short-term (1-2h) forecasting, which will most likely be the important horizon with increasing capacity in the future.

5.3 Strategic Positions of Instrumentation

Common for remote sensing is that the devices have a potential for early detection of critical weather conditions, but contain more complexity in converting the signals to wind power. A local wind speed is closer related to the wind power than a sign of a moving front in the Atlantic, which is going to approach the wind farm clusters some hours ahead. From the results in chapter 3.2, Section 3, we conclude that more than 40% of the total day-ahead error remains on the wind farm level. What remains on aggregated level is complicated to estimate. Therefore, it is also non trivial to evaluate potential improvements from remote sensing without carrying out a pilot project.

5.3.1 Potential benefits of RADAR

The advantage of RADAR measurements is that is data coverage where it is needed in a high time resolution and the signal is easy to subjectively interpret in a weather context, but complicated to convert into a wind power forecast.

A RADAR signal only provides a fingerprint of the best fit to a forecast. When used together with an ensemble forecasting system, it in fact only provides information that can be used to determine the weight coefficients for each ensemble forecast member. If the target variable is a meteorological variable, the weight coefficients will approach an even weight on all forecast members faster. In this way a fraction of the large errors can be improved several hours ahead, which would increase the intra-day market potential over time. When run every 15 minutes, RADAR based forecasting is a fingerprint matching. This strategy fits well to a continuously running ST forecast approach and would complement the wind farms signal, because they tend to improve mostly on the 1st forecast hour. Thus, the use of RADAR data is a pure software solution, which does not impose additional requirements on wind farms and it is deploying existing remote sensing signals.

Before the value of RADAR information has been analysed in detail, it is hard to justify fixed mounted remote sensing instrumentation along the coast at much higher cost for installation and maintenance and risks due to the lack of experience of SODAR/LiDAR technologies in real-time applications in Ireland. The use of RADAR data can be seen as supplementary information to the weather forecast, because it is the meteorological community's most important information system when it comes to the ultra short-term forecasting. The reliability is therefore high and the spatial coverage is suitable for the power system.

The reason why there is no experience using RADAR signals in the context of wind power forecasting is due to the power system design and focus on the day-ahead horizon. In a rolling intra-day market the RADAR signals have higher value. When that is said, the RADAR will only be a refinement of the power forecast to reduce phase errors, provide more detail in ramping and generally more constant forecast accuracy. The wind farms accuracy won't improve.

5.3.2 Potential benefits of coastal SODAR or LIDAR systems

Because SODAR and LIDAR instruments in the past have been used for short measurement campaigns, collecting historical time series over a limited time period, we find it hard to justify going ahead with such technologies at present. There are 2 projects that have employed LiDARs and SODARs in the context of real-time wind power, the Wind HUI project in Hawaii [Nakafuji, 2012] and in the WFIP project in the USA [Marquis, 2014, Wilzcak, 2014].

In both projects these instruments have not been used as alternatives to met masts, but rather as additional data information to the weather forecasting assimilation models and to increase situational awareness of critical weather situations.

The arguments for such remote sensing are that direct early detection of deviation between a forecasted and actual condition adds security and economic value to the power system. Where RADARs will indicate the movement of rainfall, the SODAR/LiDAR will show the wind speed associated with the movement. There is additional energy in weather systems from the rotation of slow winds on one side and strong winds on the other side, which RADAR signals will typically under-estimate. However, it has been shown in the Wind HUI project [Nakafuji, 2012], the WFIP project [Wilzcak, 2014] and a study carried out in Ireland in 2011 [Lang, 2011] that SODARs and LiDARs sometimes also have difficulties with the collection of data in such conditions. Such early detection could be achieved via SODAR's on remote locations with solar powered systems, which would be GSM connected. Frequent reporting would allow the forecasting system to correct phase errors earlier. A sufficiently dense network of high frequent wind speed measurements at the west and north coast would be able to provide evidence of young low pressure systems with sharp fronts at an early stage.

Common features of such low pressure systems are that they develop, when the sea surface temperature is considerably higher than the air temperature. This implies that the air flow must be from the north-west over a period of time. The strong wind then develops close to the low on the south side.

The ideal measurement location is therefore westward of high concentrations of wind power capacity. A northward position might not give an indication of the front and a too southward position will give a delayed signal, because such fronts turn anti-clockwise while moving eastward. Scaling this up could indicate that 4-5 strategically chosen locations would cover the west and north coast well.

There is no particular reason to cover the south coast. Low pressure systems rarely develop fast, if they travel northward in the Atlantic. There are wind farms along the coast, but there is rather little possibility that multiple wind farms and capacity will start ramping concurrently. A network of SODAR devices seems to be the most feasible future solution to utilize strategic positions, but the justification of such devices would maybe require an event based economic solution, where cost per MW forecast error and lead time is used to calculate the value of a SODAR/LiDAR network. Alternatively, a socialised cost over all wind farms and per MW may be feasible and would not put too much burden on the individual wind farm, but instead cover and treat all wind farms equal.



6. Reference to applicable standards

In the previous sections, we have been analysing the use of meteorological data for the Irish electrical grid both from a theoretical point of view and also from the practical side of reviewing the state of data quality that is delivered to the Eirgrid Group. In this part we want to bring this knowledge into context of technical requirements that can lead to a higher data quality and thereby improved forecasting, situational awareness and grid operation.

6.1 Meteorological Measurement Standards in Resource Assessment

While we have been mostly focusing on the operational phase of the wind projects so far, standards regarding measurements and design of measurement collection in the wind energy and power industry regarding meteorological measurements have so far only been developed for the planning and commissioning phase of wind farms. Here, the meteorological measurements serve as an indicator of the wind resource and expected power output at the site of interest for the financing of a wind project. The European Wind Energy Association (EWEA) has through an EU funded project in the "Intelligent Energy - Europe" program (2007-2013) established a specific web site, where a number of facts are summarised that describe the important aspects of measurement campaigns for the establishment of wind energy projects [EWEA, 2016]. The most common types of measurements that are taken in this phase are:

- Mean wind speed
- Maximum three-second gust wind speed
- True standard deviation of wind speed
- Mean wind direction
- Mean temperature

The EWEA webpage points to three parties providing recommendations on minimum technical requirements for anyone "intending to make bankable wind measurements" [EWEA, 2016]:

- the International Electrotechnical Committee (IEC)
- the International Energy Agency (IEA)
- the International Network for Harmonised and Recognised Wind Energy Measurement (MEASNET)

The IEC 61400-12 standard has been drafted for "Power performance measurements of electricity producing wind turbines" and provides in Annexes A to K guidelines around the setup of meteorological measurements and the respective measurement campaigns. While the measurement procedures and the derived results are much geared towards the overall consistency of the manufacturers power curve and the prevailing wind resource, there are a number of Annexes that are relevant for the later operation, where real-time measurements of the wind resource at the site are required.

Annexes D and E deal with the evaluation of uncertainty in measurements and the theoretical basis for determining the uncertainty of measurement. Annex F deals with the calibration of instruments, the measurement procedures and the analysis of the data. Annexes I and J which deal with the classification of anemometry and the assessment of the cup anemometry.

The IEA Wind "Task 11: Best Technology Information Exchange Recommended Practices" have drafted best practice guidelines that assist in implementing wind energy projects and to comply to the requirements set out in the IEC 61400-12 [IEA Wind Task 11, 2016]. The recommended practices by IEA Wind task 11 contain all aspects of a wind energy project from the site assessment to the noise regulation and the general wind integration.

In their recommended practices guide 11, wind speed measurement and the use of cup anemometers are also dealt with [IEA Wind Task 11, 2009]. It is in fact a best practice guide for the IEC 61400 MT 13 with updated power performance measurement standards. The guideline 15 deals with ground-based vertically-profiling remote sensing for wind resource assessment [IEA Wind Task 11, 2013], especially in cold climates, complex terrain and with increasing hub heights, where met masts are expensive and planning permissions are more complicated.

The International Network for Harmonised and Recognised Wind Energy Measurement (MEASNET) published a guideline on cup anemometer calibration [MEASNET, 2009], providing information on how to calibrate cup anemometers to fulfil the IEC standards. These guidelines are useful and can be used in the operational phase of the wind integration as well to set up technical requirements for the instrumentation to be used for the real-time delivery. Additionally, the integrity of the measurement procedure is described and it is recommended to follow the ISO/IEC 17025 standard. Here, the management and technical as well as reporting requirements for measurement campaigns are standardised.

6.2 Meteorological Monitoring Guidance

The United States Environmental Protection Agency (EPA) provides a "Meteorological Monitoring Guidance for Regulatory modelling Applications" [Environmental Protection Agency, 2000], which is a guideline on the collection of meteorological data for use in regulatory modelling applications such as air quality. It provides recommendations for instrument, measurement and reporting for all main meteorological variables used in meteorological modelling. In Section 4 of the guideline, the EPA provides a table with recommended system accuracies and resolutions for especially wind speed, wind direction, ambient and dew point temperatures, humidity, pressure and precipitation. Table 6.1 shows the EPA accuracy recommendation that could be used as guidelines for the met masts and any alternatives. Another useful guidance of EPA are the sampling of data signals and the recommendations regarding data sampling and averaging. EPA recommends for data communication purposes for example that an average over a specific time interval should never have less than 60 signals [EPA, 2000, 4.5 Sampling Rates].

Chapter 8 of the EPA guideline provides recommendations of quality assurance and quality control of the instruments and data communication. One aspect mentioned in the guideline that is important and ensures high quality data from the met mast instruments is to let the operators of the instrumentation carry out installation testing with appropriate documentation of the correctness of instrument performance according to the manufacturers specifications.

Meteorological Variable	System Accuracy	Measurement Resolution
Wind Speed	± 0.2 m/s (+ 5% of observed)	0.1 m/s (horizontal and vertical)
Wind Direction (azimuth and elevation)	± 5 degrees	1.0 degree
Ambient Temperature	$\pm 0.5^\circ\text{C}$	0.1 C
Dew Point Temperature	$\pm 1.5^\circ\text{C}$	0.1 C
Precipitation	± 10 % of observed or ± 0.5 mm	0.3 mm
Pressure	± 3 mb (0.3 kPa)	0.5 mb

Table 6.1: United States Environmental Protection Agency's recommended system accuracies and measurement resolution [EPA, 2000, Table 5-1].

Once this acceptance testing protocol is delivered to EirGrid, quality control of the instruments can take place in cooperation with the forecaster. Another way to ensure high data quality is to set accuracy and resolution requirements for the instrumentation and verify at start-up of the wind farm that the instrumentation has been chosen according to the requirements. The data quality can then again be verified in regular intervals in corporation with the forecaster.

6.3 Representativeness of measurements and fit to Forecasting

The MEASNET has also released a guideline on site assessment, which has a number of important aspects, also for the operational measurement setups regarding representativeness of masts and their outreach [MEASNET, 2016]. In the guideline the representative radii, which are defined as "the maximum distance of any wind turbine from the nearest measurement mast" are defined for different terrain classes and mast heights. The typical recommended mast height are $2/3$ of turbine height and a distance between 2km to 10km in a radial context from the nearest wind turbine. The guideline points to some important meteorological aspects regarding type, height and distance of measurements to be reliable and undisturbed and hence methodologically useful [MEASNET 2016, pp9-10].

In the numerical weather prediction models (NWP), the wind is modelled in layers, which means that if measurements are aligned with model levels the forecasts will fit the measurements better and vice versa. Although there are no common level structure between different NWP models at different suppliers and centres, there is a physical structure that is common for all NWP models. This structure is defined by physical aspects of the model with respect to influence of ground based vegetation and terrain complexity. In most NWP models there are 2 – 4 major levels within the first 100-150m above the ground that are used for the vertical structure of the atmosphere in the forecast steps. Mostly, the first two layers are around 30m and 100m. There are no exact numbers, because most NWP models use terrain following levels, a so-called sigma pressure coordinate system, where pressure levels are scaled with the surface pressure and therefore change in elevation above the ground according to the elevation at the surface and the corresponding surface pressure [see e.g. Wikipedia, Möhrlen, 2004, pp21-26].

The levels around 30m and 100m are usually used to interpolate the physical parameters such as the wind vector, temperature, pressure, humidity to the typical heights used in wind power forecasting. These levels are even used, if there are other levels present in the model that could be used. The reason for this is that the sigma levels change with pressure and temperature and are hence not fixed to a specific height above ground. Another reason is that changes in vegetation (land/water) at the surface should not have an influence on the computations within a grid cell.

A typical vertical coordinate system can be found in the "Irish Study" experiments carried out by Möhrle [2004, pp38]. In the early days of forecasting, the 10m wind was often used and up-scaled to hub height. It has been shown that this is for the described reasons a bad estimate of the power at hub heights above 30-50m. There are low level jets that the wind turbine blade reach up into, while the 10m signal does not "see" such air movement.

Drechsel et al. [2012] has shown in a recent study that the down-scaling from 100m winds delivered by the ECMWF forecast system yielded much lower errors across a large number of European sites of different type and complexity than the up-scaled 10m wind. The relevance of the modelling aspect comes into play when considering technical requirements for the delivery of independent mast measurements.

Here, it is important to know that the 2/3 rule from the site assessment might be a good guideline, however, only, if the 2/3 rule is for a significant amount of the installed capacity around a relevant model level. The same is true for traditional 10m met masts. Pinson and Hagedorn [2009] made an investigation on the usefulness of such met mast data from the GTS (global telecommunication system) collected over Europe and verified it over Denmark and Ireland.

They employed an uncertainty correction for the measurements, because no quality measure was available for these sites. Nevertheless, if the height of the measurement does not reflect the wind profile that the turbine experiences, the measurements do not fit the power output of the wind farm. In order to investigate the situation in Ireland, we have been looking at the hub height of all wind farms, their installation year, the amount of installed capacity per hub height level and the 2/3 height aspect and compared it with wind farms in Germany. Figure 6.1 and Figure 6.2 show a comparison between Germany and Ireland.

While in Germany the hub height increased already over the 30m mark in 1992 and the hub height is increasing over the 100m mark since around 2010, Ireland's development shows a different pattern and even though the largest turbines in Ireland today reach around 90m, there will most likely not be higher hub heights in the years to come.

This signal can be explained by the load factor difference, where in Germany the good resource areas are taken and the turbines must reach higher up in the southern parts of the country to reach a reasonable power output, this will not be a necessary step in Ireland.

Therefore, we can expect that the hub height around 60-80m will stay for a long time as a standard in Ireland. In Figure 6.2 the light blue line shows that the largest portion of the 50% hub heights are around the lower model level at 30m. We can also read out of the underlying data of Figure 6.2, shown in Table 6.2 that the average hub height for the 50% of hub height is 32m and that 95% of the installed capacity's 50% hub height is between 30m and 40m. The average hub height of the total fleet is 64m.

Table 6.2 also shows that more than 60% of the wind turbines installed in Ireland are above 60m.

What that means is that a 50% rule instead of the 2/3 rule for met mast measurements may be an alternative to hub height measurements in order to increase the coverage of wind data for real-time operations in the future as discussed in the future scenarios in section 4.3.

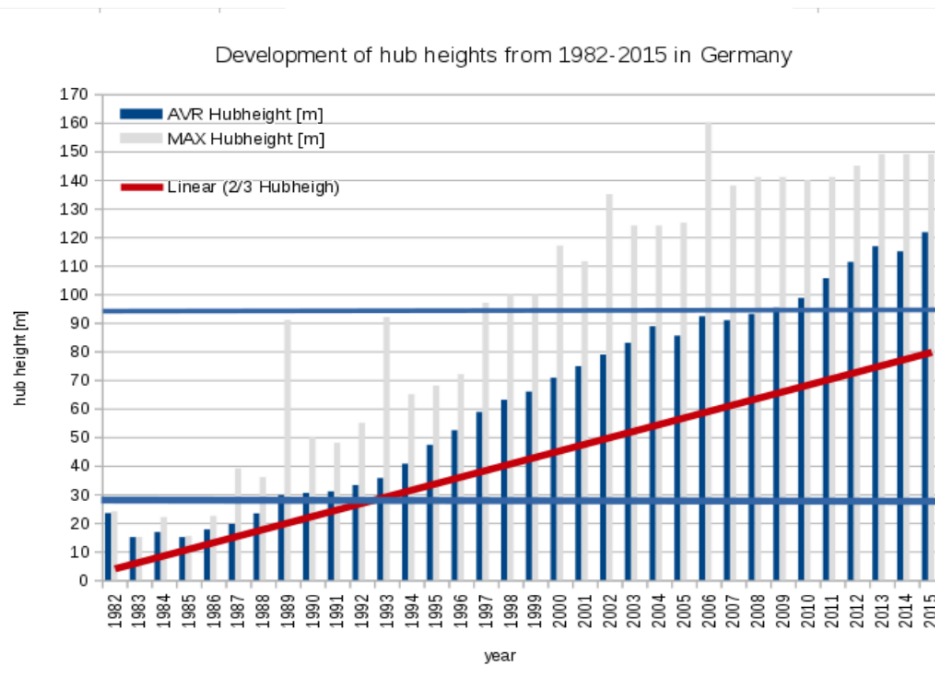


Figure 6.1: Development of the hub height of installed wind turbines in Germany from 1982 to 2015. The dark blue bars indicate the average hub height in the respective year, while the light blue bars show the turbine(s) with the highest hub height in that year. The red line shows the trend of the height above ground for the 2/3 of hub height.

Year	Hub height [m]	2/3 hub height [m]	50% hub height [m]	Installed Capacity [MW]	Procent of inst. Cap	Accum. Proc. of inst. cap
1998	45	30	23	5	0.20	0.20
2000	46	31	23	48	1.92	2.12
1999	47	32	24	9	0.35	2.47
1997	49	33	25	51	2.06	4.53
2001	54	36	27	8	0.33	4.86
2002	58	39	29	12	0.48	5.34
2005	60	40	30	182	7.33	12.67
2003	62	41	31	66	2.65	15.32
2008	64	43	32	156	6.29	21.61
2006	64	43	32	181	7.27	28.88
2004	65	43	33	142	5.70	34.58
2009	70	47	35	339	13.66	48.24
2010	70	47	35	179	7.20	55.44
2007	72	48	36	60	2.42	57.85
2011	74	49	37	197	7.94	65.79
2013	76	51	38	272	10.94	76.73
2012	77	51	38	104	4.16	80.89
2015	78	52	39	187	7.53	88.42
2014	89	59	45	288	11.58	100.00
AVR/SUM	64	43	32	2485		

Table 6.2: Analysis of the hub height of currently installed wind turbines in Ireland. The hub height column is the average hub height of wind turbines installed in the corresponding year.

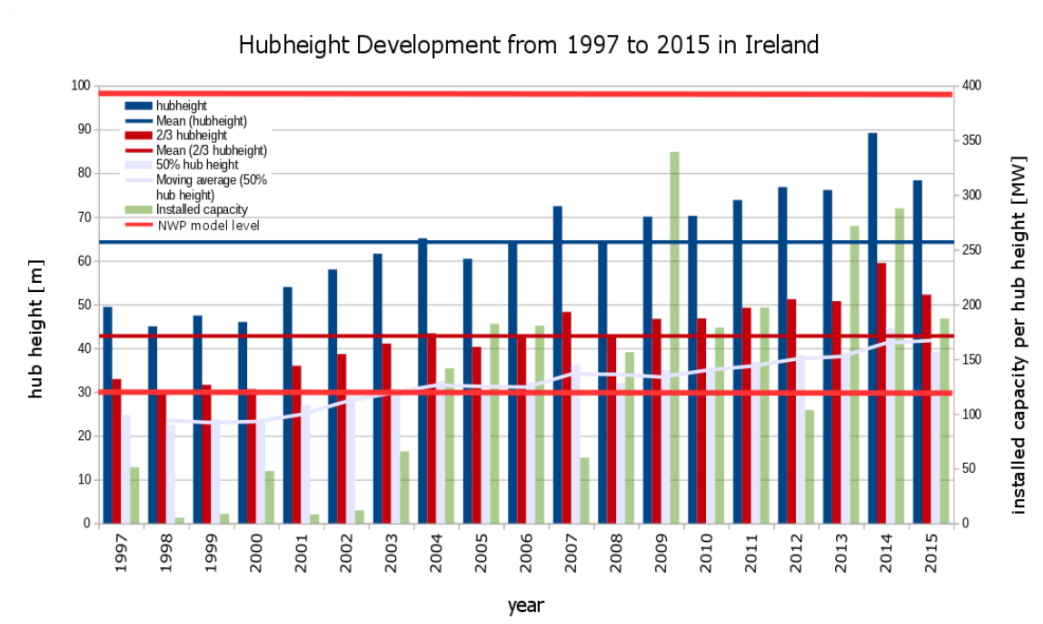


Figure 6.2: Development of the hub height of installed wind turbines in Ireland from 1997 to 2015. The dark blue bars indicate the average hub height in the respective year and a mean line reaching 64m. The dark red bars show the height above ground for the 2/3 of hub height inclusive a mean line reaching 43m. The light blue bars and line indicate a trend for a 50% hub height. The light red lines indicate the NWP model levels approx. height above ground. The green bars show the installed capacity per year.

Summary

1. Instrumentation calibration should as a minimum follow the IEC 61400-12 standard also for real-time operation [see also IEA Wind Task 11, 2016, MEASNET, 2009].
2. 95% of the installed capacity has a hub height between 30-40m
3. Some wind assessment recommendations are also useful for real-time operation [MEASNET, 2016]:
 - (a) mast height of 2/3 of turbine height (Ireland's average is 43m)
 - (b) distance between 2 km - 10 km in a radial context from the nearest wind turbine



7. Conclusions and Recommendations

7.1 Conclusion and Discussion

The need of accurate on-site measured wind speed data signals is increasing with the installed wind power capacity. Since wind farms have been installed with varying technologies over the past 20 years, the system does not have a single point of failure. The lack of uniformity is both a handling challenge and a reliability strength.

7.1.1 Met data from Meteorological Masts

The study has shown that a requirement for the installation of a met mast at hub height in ROI has become an obstacle for achieving high quality and sufficient coverage of on-site measured wind speed data from wind farms. There are both economic and planing permission reasons why the requirement of met masts at hub height will continue to be an obstacle. In fact, measurements taken at today's wind turbine's hub height is no longer sufficient to describe the power generation of these large wind turbines of >70 m. Due to the large rotor sweep area, the turbine sometimes reaches into different atmospheric layers, enabling the turbine to produce power, even though one of the layers may not have sufficient wind (see Section 6.3).

We have shown that there is no longer a cost-benefit ratio that is justifiable for this requirement. Met masts of 30-35m height will implicitly limit costs for all accepted means of providing met data, provide fair conditions for all wind farms and keep diversity of the signals without compromising the forecasting performance. Met masts are typically positioned along the border of a wind farm in the direction of the prevailing wind. Met mast data are superior to nacelle data with respect to their independence, but it is more difficult to get a good fit between the met mast wind speed and the power generation of the wind farm.

7.1.2 Nacelle Sourced Met data

The nacelle data is already part of the system for a number of years, but historically there was a good reason why nacelle sourced wind speed data was not accepted as a source for wind farm met data in ROI. The range, where the wind speed data was useful has only been along the steep part of the power curve due to wake effects and over-speeding of instruments when blades start to pitch.

It has been shown in this report that nacelle signal accuracy has been increasing with time; the nacelle wind speed has become more consistent with the power curve of the wind turbines due to new methodologies applied to compute a consistent wind speed.

The met mast and nacelle sourced wind speed data signals behave differently. They differ with the same magnitude to the forecast, but in different ways. The nacelle wind is optimised to the power curve equivalent wind of the current power generation. The nacelle signals are effectively delivering a vertical and horizontal average across the wind farm, while the met mast is measuring a wind farm independent, continuous signal at a fixed point and at one altitude.

We should therefore expect that the nacelle wind speed is closer to the forecast than the mast's wind speed. It has been found that this is not the case, because it is a fictive and in most cases not raw measured data, but a computed wind speed taking wind farm internal and external effects on the wind speed into account. As a minimum, there are wake effects included, which would be avoided when setting up a met mast for some wind directions.

The most critical factor by allowing nacelle generated wind speeds is that it needs to be fitted to the power generation of the wind farm. If this process is done correctly, the data will pass the quality control of the forecaster. If the calibration does not or no longer fit the power generation, it will be visible in the quality control. The turbine manufacturer and wind farm operator have in that way a clear orientation for their calibration target. The risk with old wind farms that may not be in a position to deliver a good quality nacelle data signal can in that way also be reduced. The oldest example of good data is a VESTAS V66 wind farm from 2006. This wind farm is an exception from the pattern on other wind farms, where the nacelle data did only reach good quality for wind farms installed after 2013. There is reason to fear that manufacturers prioritise nacelle data for newer wind farms and wind turbine models, and that the old wind farms will lack accuracy. The quality analysis in this study showed this trend.

It also has to be expected that the accuracy of nacelle sourced wind speed signals will degrade with age as the wind turbine blades are likely to soften from load over many years. It is a slow process and not an argument against nacelle wind speed in general. With softer blades the wind farm will reach full load at a higher wind speed. It is inevitable that this will cause a bias on the nacelle wind speed to the low side. Retraining of the translation between nacelle wind speed and power generation will eliminate these risks. The nacelle computed wind speed is a better measure of the wind than the shadowed cup anemometer wind speed.

7.1.3 Quality of Met data

Our main conclusion from the investigation is that the current quality of met data from wind farms is not of sufficient quality to result in a benefit in the forecasting system unless a high fraction of the data is discarded. Especially at the high wind speed ranges there is too much uncertainty in the signals to be usable in the HSSD forecasting. These quality concerns apply to both met mast and nacelle wind speeds.

The most efficient way to overcome these hurdles is to set quality targets in combination with continuous control of the quality as part of the forecasting system and delivery requirement for the met data accuracy being 98.5% of the time at any stage of the wind farms life time. If the requirement can no longer be achieved with one method, an alternative method may be implemented. The time resolution of the met data signals has also shown to be an issue for the short-term as well as HSSD forecasting process. The analysis of data has shown that a higher resolution delivery of 1-minute averages will improve the forecasting processes significantly. This is already in place between wind farms and EirGrid, but the data is not made accessible to the forecasting process. An upgrade from 15 minute resolution to one minute resolution will facilitate the quality check of the data, the HSSD forecasting and the ST forecast will also improve significantly and the LT forecast as well. It is a low cost enhancement with considerable benefits.

7.2 Recommendations

Given that we only found good wind speed data from approximately 60% of wind farms, it is recommended to introduce a delivery requirement on wind speed data submitted by the wind farms to the transmission system operator (TSO), which should be fair to all accepted types of measured wind speeds, but ensure that the wind speeds comply to a minimum accuracy and reliability.

Handling of old and new wind farms

It is commonly used that the rules applicable for newer and older wind farms differ, because the newer wind farms have possibilities to design their project with newer technology and because it is fair that wind farms installed at higher wind penetration should be more reliable than those typically installed at low penetration levels.

Given the 20 year age difference of the currently running wind farms, there is considerable difference from wind farm to wind farm on their possibility to recover costs imposed on reliability. Small wind farms of different age distributed across Ireland are independent and do not act correlated like a new large wind farm does. The study also revealed that they are also the most predictable wind farms. However there are areas of very sparse wind speed data, which is a limitation for the forecasting. Therefore it is recommended to encourage small wind farms below 10MW to deliver nacelle wind speed data if they can, but these wind farms should be exempted from fixed delivery requirements on the nacelle data. It is up to the forecast process to make use of the data.

The accuracy requirement of future wind farms should not be limited by their age as they can plan their project according to the rules and reserve the possibility to raise a met mast in case nacelle data becomes too expensive to maintain. The diversity in terms of wind speed recording technology will lead to higher costs or disadvantages in the administration, monitoring and forecasting, but will add independence and reliability, which is important on an island grid.

Acceptance of met data from nacelle as alternative to met masts

The results of the study objectively allow nacelle data signals as alternative source of met data in Ireland. The conclusion of the study is that a path towards a uniform wind speed source type and quality is therefore not feasible nor required.

The nacelle wind speed shall not be seen as an independent true signal and there are serious risks that the wind speeds will be systematically different between different wind farms and that it will be more difficult to prove or disprove the correctness of the data. For wind farm manufacturer, compliance to a power curve could be seen as a competition factor. As an example, the study has identified that ENERCON is well ahead on the accuracy level for nacelle sourced wind speed data, especially near the HSSD point. However, if the wind farm delivers a consistent wind speed and potential power generation, it will be difficult to argue that the wind speed is incorrect. This is also the case at the HSSD point.

All wind speed signals need to comply to accuracy thresholds. The study showed that cases can occur, where such thresholds are met, but the data may be unreasonable. To avoid long-lasting discussions, it is recommended that the TSOs can request a formal calibration with an independent measurement source after the IEC61400-12-1:2017 Annex I standard. This can be carried out by an on-site LiDAR recording e.g. for a month or a met mast, which may be simpler and less costly to monitor.

The overall recommendation is that nacelle sourced wind speeds can be accepted as an alternative to met masts at hub height in combination with a common minimum delivery requirement system. The requirement should be permanent for new wind farms, whereas it should for the old wind farms be e.g. a sliding reduction of the requirements to prevent wind farms from getting excessive maintenance costs towards the end of their operational phase. This could also include the reduction of height for met masts from hub height to 30-35m agl (above ground level).

Our recommendation for the allowance of nacelle wind signals as alternatives to met masts at hub height does not include remote sensing instruments such as LiDARs or SODARs. These instruments need to go through a test period of a minimum of 3 months for approval in a real-time environment. In other words, the instruments have to be capable of providing data with the required accuracy and reliability under real-time conditions, due to their sensitivity to weather conditions, which are common in Ireland.

Summary of Recommendations

1. Met Mast Alternatives

- (a) Correctly calibrated and computed nacelle sourced wind speed is an accepted source of met data (see section 3.1.4, 3.2.4 and 7.1.2 for details)*
- (b) Lowering the met mast height requirement to a height of 30m or greater.*
- (c) LiDARs will need to be able to comply to a delivery percentage of 98.5% in Ireland in order to be acceptable as alternatives to met masts*
- (d) LiDARs can be used as a calibration method according to IEC61400-12-1:2017 to proof correctness of met masts or nacelle sourced data signals*
- (e) New technologies (e.g. remote sensing LiDARs, SODARs, RADARs) should be allowed to apply as alternative measurement type or in combination with other instruments, but need to go through a real-time acceptance test of a minimum of 3 months in a windy period*

2. Met data quality

- (a) Sampling and Provision of all met data signals should be a minimum of 1-minute average based on a minimum of 12 sub-minute sample points
 - *met mast sourced wind speed signals are required to be provided from multiple cup anemometers at 3 different heights above ground level**
- (b) Accurate met data should be provided by wind farms 98.5% of the time (see 4.4)*
- (c) Continuous quality assessment of met data should be part of the forecasting system*
- (d) Accurate high-speed shutdown (HSSD) signal provision should be a requirement with validation by forecasters*
- (e) Incorporation of announcements by wind farms on full and partial scheduled and non-scheduled outages should be entered into the IT system*
- (f) Provision of accurate available active power capability (AvailActivePower) should be provided by all wind farms subject to dispatch instructions*



Glossary

agl	above ground level
AirPressure	Pressure record at mast
AirTemp	Temperature reported at mast
Availabilty	Wind farm availability
AvailActivePower	available potential generation capacity of the wind farm
HSSD	High-Speed Shut Down, as percentage of capacity shutdown due to high wind speed
LiDAR	Light detection and Ranging – is a surveying method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor.
MAE	Mean Absolute Error (see 7.2)
MEC	Maximum Export Capacity
MSEPS	Multi-Scheme Ensemble Prediction System
mw	actual power generation from the wind farm
RADAR	RAdio Detection And Ranging – is a detection system that uses radio waves to determine the range, angle, or velocity of objects
SLA	Service Level Agreement
SODAR	SOnic Detection And Ranging – is a meteorological instrument used as a wind profiler to measure the scattering of sound waves by atmospheric turbulence.
VERs	Variable Energy Resources
WindSpeed	Wind speed reported by anemometer mounted on mast
WindDirection	Wind direction on met mast



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APPENDIX: Statistical Metrics

BIAS: Indicates whether the model is systematically under- or over-forecasting

$$BIAS = \frac{1}{n} \sum_{i=1}^n (f_i - m_i)$$

where f is the forecast and m the measurement.

Mean Absolute Error (MAE): The average of all absolute errors for each forecast interval. Measures the average accuracy of forecasts without considering error direction.

$$MAE = \frac{1}{n} \sum_{i=1}^n (|f_i - m_i|)$$

where f is the forecast and m the measurement.

Mean Absolute Percent Error (MAPE): This is the same as MAE except it is normalized by the capacity of the facility.

Correlation: Correlation is a statistical technique that is used to measure and describe the STRENGTH and DIRECTION of the relationship between two variables.

$$r(x, y) = \frac{COV(x, y)}{STD_x \cdot STD_y} = \frac{\sum (x - \bar{x}) \cdot (y - \bar{y})}{N \cdot STD_x \cdot STD_y}$$

where f are the forecasted values, m are the measurements, COV is the covariance, STD is the standard deviation.