Should future wind speed changes be taken into account in wind farm development?

Annemarie Devis\textsuperscript{1,2,4}, Nicole P M Van Lipzig\textsuperscript{1} and Matthias Demuzere\textsuperscript{1,3}

\textsuperscript{1} KU Leuven, Department of Earth and Environmental Sciences, Celestijnenlaan 200 E, B-3000 Leuven, Belgium
\textsuperscript{2} Storm, Katwilgweg 2, B-2050 Antwerpen, Belgium
\textsuperscript{3} Ghent University, Laboratory of Hydrology and Water Management, B-9000 Ghent, Belgium
\textsuperscript{4} Author to whom any correspondence should be addressed.

Keywords: wind energy, climate change, wind turbine, Earth system models, Europe, wind resource assessment, multimodel ensemble

Abstract
Accurate wind resource assessments are crucial in the development of wind farm projects. However, it is common practice to estimate the wind yield over the next 20 years from short-term measurements and reanalysis data of the past 20 years, even though wind climatology is expected to change under the future climate. The present work examines future changes in wind power output over Europe using an ensemble of ESMs. The power output is calculated using the entire wind speed PDF and a non-constant power conversion coefficient. Based on this method, the ESM ensemble projects changes in near-future power outputs with a spatially varying magnitude between $-12\%$ and $8\%$. The most extreme changes occur over the Mediterranean region. For the first time, the sensitivity of these future change in power output to the type of wind turbine is also investigated. The analysis reveals that the projected wind power changes may vary in up to half of their magnitude, depending on the type of turbine and region of interest. As such, we recommend that wind industries fully account for projected near-future changes in wind power output by taking them into account as a well-defined loss/gain and uncertainty when estimating the yield of a future wind farm.

1. Introduction

The recommendations of the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) are clear: ‘Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions’ (Qin \textit{et al.} 2013). To mitigate the climate change that the IPCC expects, the European Council agreed in 2015 on the ambitious target that by 2030 all member states should gain at least 27\% of energy from renewable sources, such as wind energy (Canete 2015). To achieve this goal, European countries will have to increase their investments in the development of wind energy projects. To minimise the investment risks associated with such developments, wind industries commonly make an \textit{a priori} estimation of the expected wind power yield over the next 20 years (being the lifetime of a wind turbine). It is extremely important to make this yield estimation as adequately as possible, especially at a time when governmental support is cutting back and competition in the wind industry is growing. It is common practice in the wind industries to estimate the expected wind power yield for the next 20 years from short-term measurements and the reanalysis wind climatology of the past 20 years. Possible future changes in wind climatology are generally only addressed as an extra uncertainty (of typically 2\% for northern Europe) on the resulting estimation of the power production of the farm (Nielsen 2010).

However, research on wind climatology clearly indicates that the yield from wind turbines is sensitive to climate change (Pryor \textit{et al.} 2005a, Hueging \textit{et al.} 2013, Reyers \textit{et al.} 2015, Tobin \textit{et al.} 2016, Carvalho \textit{et al.} 2017). Recent projections based on the global climate models (GCMs) of the fifth phase of the Coupled Model Intercomparison Project experiments (CMIP5) show changes in 10 m wind speeds ranging from 5\% to 10\% per century over North America (Kulkarni and Huang 2014). The CMIP5 models have also been used over Europe, where they indicate an ensemble mean increase of wind energy output for
winter in northern central Europe and a decrease in summer (except for the Baltic Sea region) (Reyers et al. 2015, Carvalho et al. 2017). A similar signal is presented by regional climate models (RCMs). RCMs expect wind power potential to increase over northern and central Europe, particularly in winter and autumn, and to decrease over southern Europe in all seasons, except for the Aegean Sea (Hueging et al. 2013). An increase in wintertime wind energy over the North and a decline in the southeast of Europe was also indicated by respectively Pryor et al. (2005b) and Bloom et al. (2008).

Although previous studies have given useful estimates on future changes in wind speed and wind power output, a number of adjustments on the commonly used methods are implemented in the present paper. Firstly, it is typically demonstrated that due to the coarse horizontal and vertical resolutions of the GCMs, many practical purposes, e.g. wind energy yield estimations, require the downscaling of GCM information to finer scales using statistical or dynamical approaches. It is acknowledged that an increased resolution generally leads to better predictions at the small scale (Hahmann et al. 2015, Santos-Alamillos et al. 2015, Carvalho et al. 2014). The benefit of downscaling in representing the local climate at higher resolution is widely outlined (Barstad et al. 2012, Reyers et al. 2015, Pryor et al. 2005a). However, in contrast to the common belief that GCMs need to be down-scaled to give a realistic description of the local climate within a climate change context, this study looks at potential power changes directly retrieved from an ensemble of CMIP5 earth system models (ESMs). It is argued that, due to the increased resolution and the improved interaction with the surface, ESMs are becoming increasingly realistic in simulating atmospheric conditions, also near the surface. This is shown by Devis et al. (2014) who found that ESMs are able to represent the wind speed probability distributions at hub heights for most regions in Europe. Apart from the satisfying skill of the ESMs, direct ESM output is preferred over downscaled data, since it has not been shown that downscaling improves the climate change signal of wind speed. On the contrary, it does induce additional uncertainties on the projections. Tobin et al. (2016) noted that a higher resolution does not lead to stronger changes in wind speed and wind power output. Therefore, the present study assesses future wind power potential over Europe using a model ensemble that is composed out of direct ESM output.

Secondly the commonly used mean wind speed (Hueging et al. 2013, Reyers et al. 2015) is not the best parameter to describe the wind climatology when the focus is on wind power output. Wind speed rather follows a skewed function (like Weibull) than a Gaussian (symmetric) function (Petersen et al. 1998, Burton et al. 2001, Monahan et al. 2011, Wieringa and Rijkoot 1983, Devis et al. 2013). Therefore, the present paper considers the entire frequency distribution instead of only the mean wind speed. By looking at the distribution of the winds, extreme winds are also taken into account. Extremes are important for wind power yield studies, since wind turbines are shut down during extreme high and low wind speeds. This might become especially important in the future climate, since the intensity and frequency of extreme wind events are expected to change based on regional climate model projections (Outten and Esau 2013).

Thirdly, it is common practice in wind power research to use a constant power conversion efficiency (Hueging et al. 2013, Reyers et al. 2015, Moemken et al. 2016), while in practice every wind turbine has a unique wind speed dependent power conversion efficiency. Calculating the power output from the mean wind speed and a constant power conversion efficiency only provides an approximation of the true wind power. Therefore, in this study, the power output calculation is based on a method that takes into account the entire frequency distribution of the wind speed and the wind speed dependency of the conversion efficiency.

Moreover, previous research efforts on wind power generally only derive the potential power output changes for one benchmark turbine type (Hueging et al. 2013, Reyers et al. 2015, Moemken et al. 2016). Yet every turbine is characterised by another wind speed dependent conversion efficiency and will therefore react differently to potential changes in wind speed, in particular to changes in extreme wind speed. To assess the sensitivity of the power output to the choice of wind turbine type, this study, for the first time, is not limited to one benchmark turbine but considers a range of different turbine types.

It is important to acknowledge that in practice ESMs are not used in a site specific wind resource assessment. On the other hand, industries commonly use one (or a few) year(s) of local measurements from a wind mast in combination with reanalysis data for the long term extrapolation. The long-term wind regime at the mast site is then further extrapolated to the turbine locations and hub heights using a terrain and wind flow model (e.g. WASP (Mortensen et al. 1993)). In complex terrain, computation fluid dynamics (CFD) methods are used to account for the non-linear effects. By using ESM output directly, as done in the present paper, the sub grid scale effects on wind speeds (like local surface roughness and orography) are neglected. However, since the present paper does not aim at performing a site-specific wind resource assessment, but rather intends to investigate potential future changes in local wind resources due to climate change (a signal that is likely to be carried by ESMs), the use of ESMs is justified. Moreover, at this point CFD models are not ready yet to perform simulations tackling the role of climate change on longer temporal and spatial scales. The trade-off of looking at longer (future) time scales and larger areas is that site specific effects are neglected.
The general aim of this work is to present near-future changes in wind power output over Europe as a tool for industries to improve their wind power yield assessments and to better estimate the uncertainties that are introduced by changing wind climatology. Power output changes are calculated from an ensemble of ESMs and an ensemble of wind turbine types. In contrast to common practice, the power calculations in this study take into account the skewed distribution of the wind and the wind speed dependent value of the conversion efficiency. A description of the ESMs and the power calculation method is given in section 2. The near-future projections in wind speed and power output over Europe as simulated by ESM ensemble are shown in section 3.1. The results of section 3.1 are for one benchmark wind turbine type and calculated using the newly presented method. Section 3.2 addresses the dependency of the presented results on the choice of wind turbine and the choice of power calculation method.

2. Data and methods

2.1. Earth system models

The present-day ESMs data used in this study is based on the historical CMIP5 ensemble experiment (1979–2005). This experiment imposes changing conditions (consistent with the observations) of atmospheric composition (including CO₂) due to the following factors: land-use, anthropogenic and volcanic influences, solar forcing, emissions or concentrations of short-lived species and natural and anthropogenic aerosols or their precursors. In other words, instead of using pre-determined inputs of atmospheric composition such as aerosols and greenhouse gases, the ESM simulates how these components change over time in response to anthropogenic activity and changing climate conditions (Taylor et al 2012). The near-future period analysed in this paper (2020–2049) follows the RCP4.5 (Representative Concentration Pathway) scenario, imposing changes in emission concentrations and land use. The RCP4.5 scenario simulates an emission peak around 2040–2050 and stabilises the radiative forcing at 4.5 W m⁻² towards the end of the century (Thomson et al 2011). The ESMs used in the model ensemble are listed in table 1. Instantaneous east- and westward wind records are obtained at model levels close to the turbine hub height (see section 2.2.1). The data is separated into five time subsets, representing instantaneous values for summer days, summer nights, winter days and winter nights (hereafter abbreviated SD, SN, WD and WN respectively) and annual mean values (AM). With these 12 hourly instantaneous data, short term systems like weather fronts will not be captured. However, we believe that not capturing the weather fronts will not induce any systematic bias. Moreover, it is assumed that 30 year periods are long enough to be representative for the climatological variability and that high-frequency fluctuations will be captured. From a climate science perspective, this separation in subsets is relevant since previous research has shown a seasonal dependency of future changes in wind speed (Kulkarni and Huang 2014) and a diurnal dependency of wind power output (Wharton and Lundquist 2012).

CMIP5 ESMs do not provide output regarding winds at typical wind turbine hub heights (Carvalho et al 2017). Previous literature on wind power potential therefore commonly works with 10 m wind speeds or extrapolations of 10 m wind speeds (e.g. (Kulkarni and Huang 2014) to represent hub height wind speeds. However, calculating hub height wind speeds from 10 m winds without information on the vertical shear or the atmospheric stability induces large uncertainties, especially when diurnal and seasonal wind speeds are modelled. To avoid inducing biases by using these dubious wind speed extrapolations, the present paper only focuses on the few ESM that provide wind speeds at a sufficient amount of vertical model levels in order to be able to interpolate the winds to the relevant hub height. From the available CMIP5 models, only five ESMs provide wind speeds at vertical model levels close to hub height. According to McSweeney et al (2015), these models are recommended to use for climate change assessments over Europe as they are skillful in representing the large-scale processes driving the European climate, simultaneously capturing the maximum possible range of future changes in surface temperature and precipitation. In addition, Iqbal et al (2017) have analysed future change to the North Atlantic jet projected by 11 CMIP5 models.

| Dataset (abbreviation) | Horizontal resolution (degrees) | Height of data levels (m) | Number of ensemble realisations | Data or modelling center | References |
|-------------------------|---------------------------------|--------------------------|--------------------------------|--------------------------|------------|
| CanESM2 (CanESM)        | 2.8×2.8                         | 42; 126                   | 10                             | CCCma                    | Chylek et al (2011) |
| NorESM1-M (NorESM)      | 1.5×1.9                         | 66; 247                   | 3                              | NCC                      | Kirkevåg et al (2008), Seland et al (2008) |
| IPSL-CM5-MR (IPSL)      | 1.5×1.27                        | 37; 113                   | 3                              | IPSL                     | Duftesnes et al (2013) |
| HadGEM2-ES (HADGEM)     | 1.875×1.25                      | 20; 80; 179               | 10                             | Met Office               | Collins et al (2011) |
| CNRM-CM5 (CNRM)         | 1.4×1.4                         | 34; 145                   | 10                             | CNRM-CERFACS             | Voldoire et al (2013) |
2.2. Wind speed characteristics and power output

2.2.1. Wind speed characteristics
This study focuses on turbine types with a hub height of 78 m. ESM wind speeds \( U \) are interpolated to the same height (represented by \( z \) in equation 1) according to the power law which is commonly used (Archer 2005, Pryor et al. 2005a, Devis et al. 2014):

\[
U(z) = U_{\text{ref}} \left( \frac{z}{z_{\text{ref}}} \right)^\alpha
\]

where \( U_{\text{ref}} \) is the known wind speed at a reference level \( z_{\text{ref}} \). \( \alpha \) is commonly assumed to have a constant value of 0.7, which is a good approximation for neutral stability conditions, but does not account for surface roughness or stability of the atmosphere. When wind speeds are known for more than one level, as in the current study, \( \alpha \) can be calculated by using the model levels above \((z+1)\) and below \((z-1)\) 78 m:

\[
\alpha = \frac{\ln \left( \frac{U(z+1)}{U(z-1)} \right)}{\ln \left( \frac{(z+1)}{(z-1)} \right)}
\]

This approach takes into account the variability of \( \alpha \) in time due to a change in atmospheric stability (Holt and Wang 2012).

2.2.2. Wind power output
The power produced by a wind turbine depends on the energy in the wind and the type of wind turbine. For wind speed \( U \) (unit: \( \text{ms}^{-1} \)), the extractable power output \( P \) (unit: \( W \)) of a turbine with rotor diameter \( R \) (unit: m), is given by

\[
P(U) = \frac{1}{2} C_p \rho \pi R^2 U^3
\]

with \( \rho \) being the air density (assumed to be a constant value of 1.225 \( \text{kgm}^{-3} \)). The power conversion coefficient \( C_p \) (dimensionless) defines the efficiency at which the turbine converts the energy in the wind into electricity (Tong 2010).

Figure 1 shows the turbine conversion efficiency curves for the wide range of wind turbines used in this study. For comparative purposes, only on-shore turbines with a hub height of 78 m, a rotor diameter between 80 and 108 m and nominal power of 1, 6–3, 0 MW are considered. The turbines generally start generating power from wind speeds of about 2 \( \text{ms}^{-1} \) and are turned off at wind speeds higher than 25 \( \text{ms}^{-1} \) in order to prevent breakdown. These are typical characteristics for operational onshore turbines. Offshore wind turbines types have not been examined, this should be kept in mind when interpreting the results over sea surfaces.

Based on the turbine conversion efficiency curves of the turbines in figure 1, the median turbine type in terms of \( C_p \) is chosen as a benchmark turbine for this study: the G90 2 MW Gamesa wind turbine. The analysis of the projected future changes in power output are performed for the benchmark turbine. The sensitivity of the resulting power output to the choice of benchmark turbine type is addressed in section 3.2.

The value for \( P \) is commonly calculated by using a constant value of typically 0.35 for \( C_p \) (Hueging et al. 2013, Reyers et al. 2015, Moemken et al. 2016) and the average wind climatology \( U \) (an approach that is
further referred to as the average wind speed approach or AW approach):

\[ P_{AW} = \frac{1}{2} \rho \pi R^2 U^3. \]  

(4)

In the hypothetical case that future wind speed would only be characterised by a change in mean wind speed, equation 4 would be an appropriate way to calculate the related change in power output. But when future wind climatologies also change in width or skewness of the distribution, equation 4 will only provide an approximation of the true power change. To be able to take into account the possible change in wind speed PDF, the power output is calculated as the power at wind speed \( U \) multiplied by the probability density distribution \( p(U) \) and integrated over the range of wind speeds. As such, the wind dependency of the conversion efficiency is also taken into account. In the remainder of the manuscript this method is referred to as the PDF approach. The impact of calculating the power output using the PDF approach is explored for the benchmark turbine in section 3.2.

\[ P_{PDF} = \int_{0}^{\infty} P(U)p(U)\,dU. \]  

(5)

The change in future wind speed and future power output is calculated for each ESM separately as the relative difference between the historical and the future value of \( P_{PDF} \). The ESM ensemble change of wind speed and power output is addressed by looking at the lowest, the middle and the highest value of change for each grid point, a multimodel-based method which is also adopted in the IPCC Fifth Assessment Report (Stocker et al 2013). Changes are considered significant when the lowest and highest grid point values are equal in sign across the ESM ensemble envelope. This high level of significance is defined as ‘virtually certain’ by the IPCC (Mastrandrea et al 2011). However, it should be recognised that the ensemble in the present paper considers a small number of ESMs. Moreover, statistics based on ranked grid point values degrade available patterns of information present in multimodel climate projections and consequently overestimate the uncertainty as represented by the model spread between the lowest and highest grid point (Madsen et al 2017).

3. Results

3.1. Wind speed and power output

A significant decrease in wintertime wind speeds in the Mediterranean region was found when analysing the ESM ensemble (figure 2): all five ESMs project a decreasing wind speed for this region. During WD, the median ensemble decrease varies between 3%–6% for some regions in the Mediterranean. In western and northern Europe, wind speeds are projected to increase up to 4%, most significantly in the region of the Baltic Sea. On the other hand, during summertime, the projected changes in wind speed are slightly less pronounced and generally marked by an increase in western and northern Europe and a decrease in northeastern Europe. In contrast to wintertime, the changes during summer are insignificant for most of Europe, except for some regions in northern Europe and the Norwegian Sea. The large difference between the lowest and highest grid point values during summer (especially during SN) indicate the disagreement between the individual ESMs about the magnitude of the potential changes in wind speed at hub heights. For the annual mean changes, a clear difference between northwestern and southern Europe is present, indicating increasing annual mean winds up to 3.5% in the northwest of Europe (with significant values in the central part of Scandinavia) and decreasing winds down to −3.5% in the south of Europe.

The projected ensemble changes in \( P_{PDF} \) of the benchmark turbine are in line with the changes in wind speed, but the amplitude of the changes is more pronounced (figure 3). Significant decreases of about 6%–12% in \( P_{PDF} \) are projected for the Mediterranean region during winter. Northwestern European areas are looking at smaller, though still significant, increases (up to 7%). During summer, most parts of Europe depict an increasing \( P_{PDF} \) (up to 6%) with the exception of northeastern Europe. The projections are most uncertain during summer, especially during summer nights over land areas. In contrast to the projections of the wind speed depicted in figure 2, the spread of the ensemble changes of the \( P_{PDF} \) projections is much wider, indicating larger uncertainties on the projection of \( P_{PDF} \) compared to the wind speed. Caution must be taken when interpreting the \( P_{PDF} \) projections at offshore locations since the benchmark turbine is an onshore turbine.

3.2. Sensitivity to turbine type and power calculation approach

Figure 4 (left column) depicts the sensitivity to the turbine type defined as the difference in power output change between the turbine projecting the largest
change and the turbine projecting the smallest change, relative to the historical power output of the benchmark turbine. The annual mean sensitivity to the turbine type is on average 3%–4%, with few regional variations. Focusing on seasonal variations, the sensitivity is generally larger during summer than during winter. Only in the Mediterranean region, where the largest changes in power output are expected, the sensitivity of the future change in power output to the turbine type is larger during winter, with values reaching up to 9%. During summer, the sensitivity to the turbine type varies between 2% and 7% over land surface. This means that the largest difference in power output change presented by the different turbine types

Figure 2. Projected future changes in ensemble mean hub height wind speed, calculated as \( \left( \frac{U_{\text{fut}} - U_{\text{pres}}}{U_{\text{pres}}} \right) \times 100 \). Results are shown from top to bottom for each time subset: SD, SN, WD and WN and annual mean (AN). The median of the ensemble change is shown in the middle column, while the left and right columns represent respectively the lowest and highest grid point values of the ensemble. Significant changes (lowest and highest grid point values are equal in sign) are indicated by +. Note the different colour legend values for the median on the one hand and the lowest and highest grid point values on the other.
is 2%–7% of the historical power output. These values are within the same order of magnitude as the projected future change in power output of the benchmark turbine for some regions in Europe during summer. In other words, under the assumption that the benchmark turbine projects a median change in power output (compared to the other turbine types), the projected increase in wind power during summer as presented in figure 3 could vary up to 50% for some regions if a different turbine type would have been selected as benchmark.

The power change calculations described above are based on the PDF approach, considering the entire dataset of instantaneous $U$ values as projected by the ESMs. This is in contrast to the more common AW approach, where power output is calculated from the averaged climatological wind speed and a constant power conversion coefficient. Both approaches result...
Figure 4. (a) Sensitivity of the ensemble median change in $P_{PDF}$ as presented in figure 3 to the choice of turbine type. The sensitivity is calculated by the difference between the turbine with the largest and the turbine with the smallest change in power output, relative to the historical power output of the benchmark turbine. In symbols: $\frac{\left(\max (\Delta P_{PDF}) - \min (\Delta P_{PDF})\right)}{P_{PDF,bench}} \times 100$, for which $\Delta P_{PDF} = P_{PDF,turb} - P_{PDF,bench}$ and $P_{PDF,bench}$ is the change in power output of the G90 2 MW Gamesa benchmark wind turbine. (b) Uncertainty related to the use of the AW approach in calculating the ensemble median change in $P$ as calculated by $\frac{\left|\min (\Delta P_{AW}) - \Delta P_{PDF}\right|}{P_{PDF,bench}} \times 100$. Underestimations by the AW approach are indicated with a minus (−) sign. Results are shown for each time subset: SD, SN, WD, WN and AM.
in different projections of annual mean changes in power output of 2%–3%. The difference between both approaches is slightly smaller during night than during day. Figure 4 (right column) shows that during summer the AW approach generally underestimates the change in power output over land surfaces and overestimates power output changes over the sea. The main underestimation is present over western and central Europe and the northern part of Spain during summer, meaning that the future changes in power output that are expected in these regions (as presented in figure 3) would be smaller or not-existent if the AW approach were used. During winter, the AW approach is generally overestimating the change in power output. The main effect during winter is present over sea surfaces, while over land the sensitivity to the calculation approach is smaller. Over the Mediterranean Sea and parts of central Europe, both approaches result in different projections of change in power output during winter, in such a way that the AW approach overestimates the change in power output up to 6% of the historical power output. Therefore the decreasing (increasing) power output signals over the Mediterranean Sea (parts of central Europe) as presented in figure 3 would be overestimated if the AW approach were used.

4. Discussion and conclusion

This study reports on estimating the potential change in power output over Europe under near-future (2020–2049) climate change conditions (RCP4.5 scenario), based on an ensemble of ESMs. The ensemble future change is defined as significant when all five ESMs are equal in sign. Our results show that mean wind speeds are projected to increase significantly with 2%–4% over northwestern Europe during summer and winter, while significant decreases of 3%–6% are expected for the Mediterranean in winter. Such a north-south division is also present in the annual mean values. The changes in power output are about twice as strong as the changes in wind speed. Decreasing power productions of 6%–12% and increasing power productions of 4%–8% are not unrealistic for, respectively, the Mediterranean winter and northwestern Europe. Changes in wind speed and wind power are slightly larger during the day than during the night, although the large scale processes driving the future changes in wind speed are not different for day or night. This small difference between day and night can be explained by the difference in efficiency at which these large-scale processes are transferred to the near surface level. During the day, the atmospheric boundary layer is well-mixed and signals (like the climate change signal) from the higher atmosphere are passed down to the hub height in an efficient way. During the night, however, the atmospheric boundary layer is more stable stratified and the hub height wind speeds are disconnected from the higher atmospheric layers in which the climate change signal is present. This diurnal difference in atmospheric boundary layer stability explains why the changes in wind speed (and wind power) are slightly larger during the day than during the night.

The north-south divide of the annual mean power changes is in line with the results of the dynamical downscaling of Hueging et al (2013) for the periods between 1961–2000 and 2061–2100. The expected annual mean changes in the present study (of −10%–7%) are slightly less extreme, which might be related to the downscaling and the fact that Hueging et al (2013) consider a more distant future period. However, for some regions during summer, both studies project different signals. For example, during western European summers when Hueging et al (2013) project a decrease in power output, our approach projects an insignificant increase. The significant increase in annual mean power over Scandinavia, as shown in the current study, is not projected by the CMIP5 models used in the study of Karnaukas et al (2017). Additionally, other work shows inconsistencies in this work for some regions (Tobin et al 2016, Davy et al 2018). A potential reason for these differences might be the selection of models in the ensemble. The choice of ESMs in this paper is justified because (1) these are the only models with enough vertical model levels to derive hub height winds; (2) they were shown to be skillful in representing the historical large scale circulation (McSweeney et al 2015); and (3) they do not show all the same signals of future change in large scale circulation (Iqbal et al 2017). Aside from the choice and the number of ESMs in the ensemble, the difference in projections between the present study and other studies might also be related to the difference in reference periods, to the applied downscaling method or the use of other turbine types and/or a different approach for calculating power output.

Our study indicates that these last two factors (turbine type and power calculation approach) influence the resulting changes in power output. For some regions, the sensitivity of the projected change in power output is within the same order of magnitude as the expected future change in power output, indicating that the projected change may vary up to half of its magnitude for another wind turbine type. Recognising that only a limited set of turbine types with a 78 m hub height have been considered, the actual value might be higher, especially when taller wind turbines are used. However, in practice, the turbine selection is not only based on its expected yield, but also on turbulence levels and extremes, source noise, turbine dimension limitations, financial limitations, etc. The effect of the wind speed distribution approach on the projected change in power output over land is smaller than the effect of the turbine type. By using the climatological mean wind speed instead of the PDF, the power output change during summer is generally overestimated/underestimated over sea/land surface and generally overestimated during winter. During summer, the
underestimation over land is within the same order of magnitude as the expected power change, meaning that increasing power outputs during summer might be smaller or even not-existent when the climatological mean wind speed approach is used. These results on the sensitivity of the projected power change to the wind turbine type and/or power calculation approach are of great value for wind energy research in general.

Wind power yield estimations in the present paper are calculated by applying the power curve of the wind turbine on the wind climatology of a certain ESM grid cell. By doing so, only the gross energy production is calculated, i.e. the potential production of a wind farm, without any loss of production. However, in reality, a wind farm might suffer from different kinds of losses such as electrical losses, icing losses, shadow flicker losses, wake losses and many others. Some of these losses (like wake losses) are dependent on the wind speed and are expected to change as well under changing future wind conditions. True wind resource assessments take those losses into account by calculating the net energy production. Since this is not the case in the present paper, estimates of future power changes as presented in this paper should be interpreted as changes of the gross energy production, not of the net energy production values.

It is important to acknowledge that the present paper only focuses on the effect of future changes in wind speed on power production, while wind direction could also be subjected to climate change. Since the layout of wind farms (i.e. the positions of the turbines against each other) is often optimised according to the main wind direction, to maximise orographic speedup effects and minimise the wake effects, possible future changes in wind direction will affect power production. However, in some densely-built areas (e.g. the Low Countries) there is little freedom to optimise the layout of a wind farm to the main wind direction, therefore the effect of possible future changes in wind direction on the power production is complicated to address at a large scale.

Even though ESMs are not typically used in wind resource assessment studies due to their low resolution and wind direction changes and production losses are neglected, results presented in this paper can still provide useful insights for wind industries. This study shows that the common value of ±2%, which is used by industries in wind resource assessments as a proxy of the uncertainty on power production introduced by possible climate change for northern Europe, is a strong underestimation. Moreover, it is recommended that wind power changes due to future wind changes should not only be addressed as an uncertainty of wind power production, but should also (and more importantly) be defined in terms of a defined increase or decrease in wind power output. Depending on the region, season and time of the day, decreases or increases in power output up to 20% are not unrealistic. Changes of this magnitude will have an enormous effect on the yield of a wind farm project and without anticipation, these changes could be catastrophic for the wind industries.

However, the values of change and uncertainty as presented in this paper should not be used as exact values of production gain/loss in wind resource assessments. On the other hand, when wind farms are being developed in the regions where change is simulated, further investigation using high resolution models is necessary to also incorporate the site specific effects and if possible the effect of change in wind direction. Furthermore, future changes in wind power should be studied at time scales relevant for the particular wind farm project, which might be different from the 30 year period considered in the present study.

To conclude, the outcome of the present study is two-fold. First, this study contributes to the general scientific knowledge of future wind and wind energy potential over Europe in a way that generally confirms the expected future changes commonly presented by wind energy research. Secondly, and perhaps even more important, the present study suggests opening the discussion on how to use this knowledge in the wind industries to anticipate the effects of future climate change. Further research is necessary to investigate the possibility to anticipate unwanted future changes in power output by taking future wind climatology into account in decisions on turbine type.

Acknowledgments

This research is funded by a PhD grant of the Institute for the Promotion of Innovation through Science and Technology Flanders (IWT-Flanders). It has also received funding from the Flemish regional government through a contract as an FWO (Fund for Scientific Research) post-doctoral position. The ESG web portals are thanked for providing the ESM datasets. Last but not least, we want to thank Storm.

ORCID iDs

Annemarie Devis https://orcid.org/0000-0002-7302-3014
Matthias Demuzere https://orcid.org/0000-0003-3237-4077

References

Archer C L 2005 Evaluation of global wind power J. Geophys. Res. 110 D12110
Barstad I, Sorteberg A and dos Santos Mesquita M 2012 Present and future offshore wind power potential in northern Europe based on downscaled global climate runs with adjusted SST and sea ice cover Renew. Energy 44 398–405
