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RESEARCH ARTICLE

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# Which wind turbine types are needed in a cost-optimal renewable energy system?

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## Abstract

Previous research has indicated that wind power plants can be designed to have less-variable power generation, thereby mitigating the drop in economic value that typically occurs at high wind power penetration rates. This study investigates the competitiveness of adapted turbine design and the interplay with other flexibility measures, such as batteries and hydrogen storage, for managing variations. The analysis covers seven turbine designs for onshore and offshore wind generation, with different specific power ratings and hub heights. Various flexibility measures (batteries, hydrogen storage and transmission expansion) are included in the optimization of investment and dispatch of the electricity system of northern Europe. Three driving forces for turbine design selection are identified: (1) lowest cost of electricity generation; (2) annual wind production per land area and (3) improved generation profile of wind power. The results show that in regions with good wind resources and limited availability of variation management, it is cost-efficient to reduce the variability of wind power production by adapting the turbine design. This remains the case when variation management is available in the form of batteries, hydrogen storage and transmission system expansion. Moreover, it is more cost-effective to improve variability by changing the specific power rating rather than the turbine hub height.

**KEYWORDS**
electricity system, flexibility measures, specific power, wind power

## 1 | INTRODUCTION

Wind power will play an important role in future energy systems globally. However, the variability inherent to generation of electricity from wind turbines poses a major challenge for electricity systems with large-scale wind power deployment.[1] Various technologies exist that can manage variations in electricity generation.[2] Providing the appropriate form of variation management is critical, and the associated costs can present a hurdle for systems that have a high share of wind power.

However, wind turbines can be designed to have less-variable power generation, thereby reducing the cost for the provision of variation management. As shown by Hirth and Müller,[3] this can be achieved by increasing the rotor diameter relative to the generator size, improving generation at low wind speeds and/or increasing the hub height to improve the incoming wind speeds in general. These aspects of wind turbine design have a significant effect on the investment cost, which is a critical factor in the competitiveness of wind power in electricity systems. It is, therefore, of interest to understand the situations in which the benefit of reduced variability is outweighed by increased costs.

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The literature concerning cost-optimal wind turbine designs can be divided into (1) studies investigating turbine designs with a focus on electricity system considerations and (2) studies focusing on determining potentials and levelized generation costs using advanced turbine designs.

Energy systems' modelling studies typically consider the development of costs for wind power but fail to include the development of technical properties. The trend in the last decade has been towards turbines with lower specific power (SP) and increased hub height,[4] although this is not commonly reflected in energy system models. Due to the computational constraints imposed on energy system models, aggregation on the spatial scale is common. Similarly, assessments of cost-optimal energy system compositions typically only include a single turbine design to reduce the number of technologies and, thereby, reduce the level of complexity.

Some system studies that include greater detail on wind turbine designs have been conducted in recent years. Hirth and Müller[3] have studied two turbine designs with SP ratings of 470 W/m$^2$ and 210 W/m$^2$ and have concluded that low SP designs can increase the value factor of wind power, especially in cases with increasing wind penetration. Their findings suggest that advanced turbine design is a substitute for, rather than a complement to, other flexibility measures. In their work, they compare an electricity system consisting of wind power with low specific power to an electricity system consisting of wind power with high specific power. The employed model does not include hydrogen storages and grid-scale batteries.[3] Swisher and colleagues[5] included seven turbine designs, with SP ratings ranging from 335 W/m$^2$ to 100 W/m$^2$, which could be invested in at the same time. Their work adds to previous work in the field by including wind turbines with very low SP ratings and by allowing the system to comprise a mix of turbine designs. However, the capacity densities were kept the same for all the designs.[5] Dalla Riva et al[6] included three turbine designs, with SP ratings ranging from 325 W/m$^2$ to 175 W/m$^2$, and they concluded that a low SP rating enables higher market values. Changing the SP rating has been shown to have a greater impact than increasing the hub height.[6] In similarity to the study of Hirth and Müller,[3] systems with low and high SP turbines were compared to each other, and flexibility measures were not included in the analysis performed by Dalla Riva et al.[6] None of the above-described system studies have considered the reduction in capacity density that, given the same relative spacing between turbines, occurs when the rotor diameter is increased. Bolinger and co-workers have suggested that wind turbines in Europe have historically had higher SP ratings compared to those located in the United States, due to the limited availability of land for wind power production.[7] Thus, including the effect of turbine configuration on the capacity density and, consequently, the land area use of wind power should be considered.

Studies focusing on wind power potentials and turbine design include additional features, such as higher spatial resolution, multiple meteorological years, and a higher number of turbine designs. Rinne et al[8] have investigated four different turbine designs in the SP rating range of 470–240 W/m$^2$. They found that lower SP designs have a lower levelized cost of electricity (LCOE) and, therefore, increase the economic feasibility of wind power in Finland, even when considering changes to capacity density. These authors emphasize the importance of including the technological development of the turbines.[8] Ryberg et al[9] have determined the European onshore wind potentials using advanced turbine designs and 37 years of wind speed data; using a wide range of turbine hub heights and powers ratings, the design with the lowest LCOE for each square kilometre was determined. The method that they employed uses high spatial and temporal resolutions, and the capacity density is considered by explicit placement of the turbines.[9] Bolinger et al[7] have determined the LCOE for each $2 \times 2\,\text{km}^2$ area in the United States using 7 years of meteorological data. In that study, turbine designs were derived from the Year 2018 average US turbine and featured development pathways for constant, high and low SP ratings. It was found that low SP turbines have lower LCOE values, especially in sites with poor wind resources.[7] Even though the above-mentioned studies have focused on detailed wind turbine design, the impact of the surrounding electricity system on turbine design was not considered.

The present work aims to fill this gap in the knowledge by assessing the cost-optimal turbine designs from the electricity system perspective, for both onshore and offshore wind power, considering the relevant forms of flexibility measures. In this way, the impacts of flexibility measures on the choice of wind turbine design can be captured. Changes to capacity density are incorporated to capture difference in area use of turbine designs. More specifically, this work aims to answer the following questions. To what extent is it cost-efficient for the energy system to reduce the variation in wind power production by decreasing SP and/or increasing hub height of wind turbines? How does the availability of flexibility measures affect this result?

The contributions of this work are two-fold. First, it explores of the driving forces behind wind turbine design. Historically, attaining the lowest cost of electricity has been the main impetus for wind turbine development. This work sheds light on land area and variability as motivators of wind turbine development, as there are relevant factors for highly renewable energy systems. Second, this work provides an understanding of how changes in turbine design influence the variability of wind power generation. In electricity systems that have high shares of wind power, the variations are predominantly caused by variations in the generation profile of wind power itself. This work investigates how the variations at the electricity system level can be reduced already on the generation side.

## 2 | METHOD AND MODEL

This section starts with a description of the included wind turbine designs. This is followed by a description of the procedures used to determine the cost and technical properties of the wind turbine designs and wind speed data. The section finishes with an explanation of the energy system

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model, the modelled scenarios, and the metric used for assessing variations in the electricity system. The ways in which the detailed processes are used in combination are illustrated in Figure 1.

## 2.1 | Wind turbine configurations

Table 1 presents the technical and cost data for the turbine designs implemented in this work. Turbine design in this work refers strictly to the hub height and SP rating of the wind turbine. The choices of turbine designs for this work are based on their possible developments. It is not our intention to predict what the wind turbine of the future would look like. Instead, the purpose is to illustrate how these turbine designs perform from the electricity system perspective, considering the interaction effects with the system.

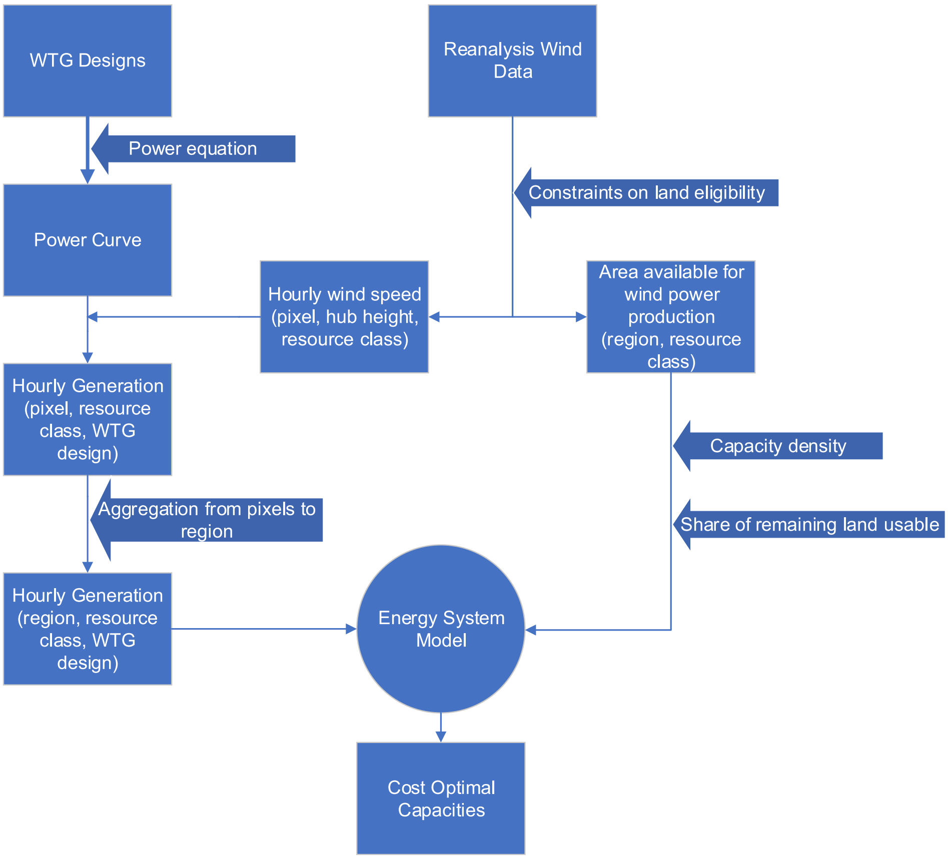


**FIGURE 1** Flow chart depicting the steps involved in the method.

**TABLE 1** Technical data of wind turbine designs and cost of corresponding wind farms included in this work.

| Parameter | | Onshore | | | | Offshore | | |
|---|---|---|---|---|---|---|---|---|
| | | A | B | C | D | E | F | G |
| Specific power | $W/m^2_{rotor}$ | 300 | 200 | 100 | 100 | 300 | 200 | 200 |
| Hub height | m | 100 | 100 | 150 | 200 | 150 | 150 | 200 |
| Capacity density | $MW/km^2_{land}$ | 5 | 3.3 | 1.7 | 1.7 | 8 | 5.3 | 5.3 |
| Cut in wind speed | m/s | 3.5 | 3 | 2.5 | 2.5 | 3.5 | 3 | 3 |
| Cut out wind speed | m/s | 25 | 20 | 15 | 15 | 25 | 20 | 20 |
| Investment cost | $EUR_{2015}/kW$ | 961 | 1161 | 1686 | 2136 | 1545 | 1770 | 2220 |
| Running costs | $EUR_{2015}/MWh$ | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| Fixed O&M costs | $EUR_{2015}/kW/year$ | 12.6 | 12.6 | 12.6 | 12.6 | 36 | 36 | 36 |

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Four onshore and three offshore turbine designs are considered. Design A is approximately the average design of newly installed turbines in Europe, with hub height of 100 m and SP rating of 300 W/m$^2$.[10] Design B represents low-SP turbines that are currently being installed, with hub height of 100 m and SP rating of 200 W/m$^2$.[11] Design C entails a theoretical future development of low-SP turbines that have a hub height of 150 m and SP rating of 100 W/m$^2$.[5] These designs are in line with those described in other publications.[7,9] The 200 m hub height, 100 W/m$^2$ SP design (Design D) reflects an ambitious development targeting high towers and low-SP turbines. Offshore turbines generally have higher generator capacity ratings than onshore turbines, so they have higher SP ratings. Both historical and predicted developments show no indication of low-SP offshore turbines. For this reason, no designs with 100 W/m$^2$ SP are included for the offshore turbines. In fact, 200 W/m$^2$ SP offshore already represents an ambitious development toward low SP and a deviation from the status quo. For the 300SP onshore turbines, a capacity density of 5 MW/km$^2$ is assumed, roughly corresponding to a 10D (rotor diameter, D) downwind by 5D crosswind spacing.[1] The offshore 300SP design assumes 8 MW/km$^2$, corresponding to a 8D downwind by 4D crosswind spacing. The capacity densities of 100 and 200SP turbine designs are then determined by accounting for the increased rotor diameter (D).

### 2.1.1 | Technical properties of wind turbine designs

The power generation characteristics of a wind turbine are commonly calculated using the power equation, which states the relation between wind speed and generated power, as expressed in Equation (1).

$$P_{\text{mec}} = \frac{1}{2}\rho_{\text{air}} A_{\text{rotor}} u_{\text{wind}}^3 C_p(\lambda,\theta) \tag{1}$$

$\rho_{\text{air}}$ is the density of air (1.225 kg/m$^3$), $A_{\text{rotor}}$ represents the area swept by the turbine's rotor, which varies according to the turbine design, and $u_{\text{wind}}$ is the wind speed at hub height. The maximum coefficient of performance $C_p^{\text{max}}$ is 0.46.[12]

Power losses in a wind farm can be divided into internal losses and external losses. Internal losses constitute wake losses, which reduce the energy of the incoming wind by a fixed 12.5%. External losses encompass downtime and transmission losses to the grid and amount to 7% on an annual average basis.[13] The normalized power curve is therefore reduced by 7% at all times, never reaching more than 93%. Normalization is done to facilitate comparison between designs and accomplished by dividing the power generated at each wind speed by the maximum generation of the curve. For wind speeds higher than the rated wind speed, the internal losses do not contribute to energy losses, whereas external losses always reduce the generated electricity by the same percentage.

A normal distribution with standard deviation of 1 m/s is applied to the incoming wind speed $u_{\text{wind}}$. This accounts for some of the local variability in wind speed that is not captured due to aggregating spatially and temporally. The resulting multi-turbine power curves, including losses, are presented in Figure 2.

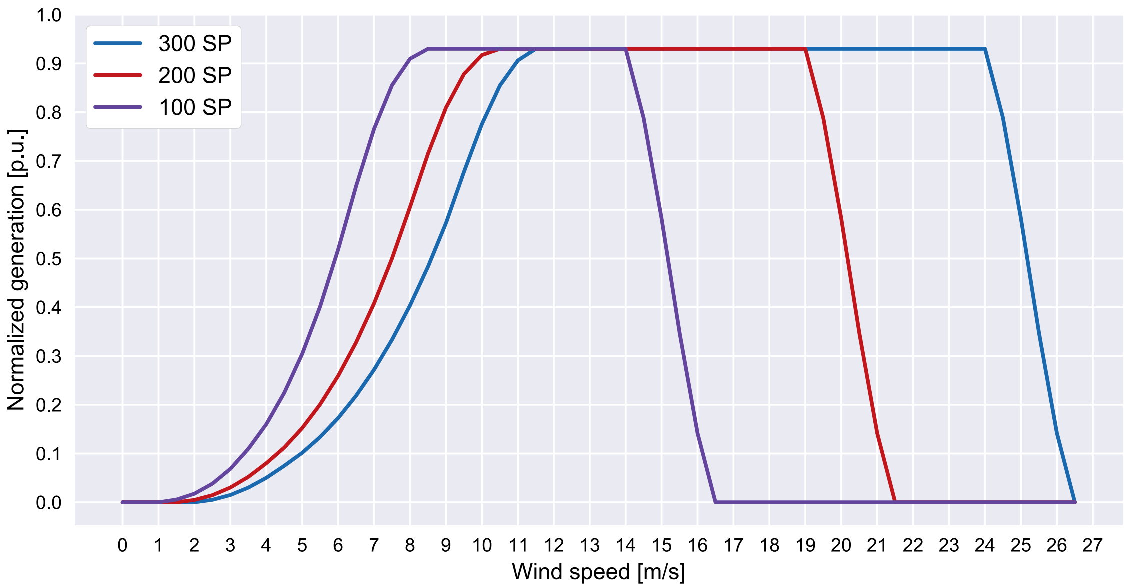


**FIGURE 2** Multi-turbine power curves for the included turbine designs.

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### 2.1.2 | Cost properties of wind turbine designs

The investment and running costs of the wind turbines are adapted from the Danish Energy Agency's estimates for Year 2050.[14] Additional costs related to reducing the SP rating and increasing the hub height are estimated using a range of values from previously conducted studies.[6,7,15,16] These estimates are based on a mix of historical observations and bottom-up cost estimates.

While it is difficult to define an exact value, a range of estimates can be established. Wiser and Bolinger (2019) found a cost increase of 90–170 USD/kW per 100 W/m$^2$ reduction in SP.[7] BNEF has reported a 100 USD/kW increase for a 40–50 W/m$^2$ reduction. Bolinger et al. have used a CapEx increase of 240 USD/kW when changing the turbine design from an SP rating of 270 W/m$^2$ to one of 150 W/m$^2$, yielding a 200 USD/kW premium per 100 W/m$^2$ reduction, although they point out that adopting an even lower SP rating has the potential to escalate costs.[7] Costs also increase exponentially when SP ratings are reduced by installing larger rotors, in part due to the square-cube law. In the present work, reducing the SP rating from 300 W/m$^2$ to 200 W/m$^2$ increased the investment cost by 200 EUR$_{2015}$/kW. A further reduction in SP from 200 W/m$^2$ to 100 W/m$^2$ increased the investment cost by an additional 300 EUR$_{2015}$/kW. A sensitivity analysis of the CapEx cost increase for the reduction of SP from 200 W/m$^2$ to 100 W/m$^2$ was carried out to account for the uncertainty in the cost increase in this range of SP ratings.

Compared to how the SP rating affects the turbine CapEx, less work has been performed on the impacts induced by increasing the hub height. The increase in CapEx for greater hub heights is based on a survey of manufacturers of German onshore WTG projects from 2016/2017,[15] and a bottom-up estimation conducted by NREL.[17] In the present work, increasing the hub height from 100 m to 150 m increased the investment cost by 225 EUR$_{2015}$/kW. For tower heights >150 m, road-based transport of tower elements and erecting the towers become challenging and more costly. A further increase in hub height from 150 m to 200 m increased the investment cost by an additional 450 EUR$_{2015}$/kW.

The final CAPEX for the 100 SP turbine is in a similar range to that established by Swisher and colleagues, who used a bottom-up, WISDEM-based cost model.[5] Table 1 lists the CapEx and OpEx values used in the modelling of each turbine design.

## 2.2 | Wind data

The wind speed data used to generate the hourly generation and resource potentials are created with a GIS-based approach using GlobalEnergyGIS.[18] In this approach, the studied regions are divided into $1 \times 1$ km cells. Available land for onshore wind power is determined by excluding protected areas, bodies of water, wetlands, and densely populated areas. Offshore is limited according to the maximum distance to shore and the water depth. Remaining cells for onshore and offshore wind generation are assigned to a resource class according to their average wind speeds, provided by the Global Wind Atlas (GWA) 3.0,[19] and the intervals provided in Table 2.

Hourly wind speeds for 100 m altitude are based on the ECMWF ERA-5 reanalysis dataset[21] using 2012 as the meteorological year. The bias in the wind data is reduced with the help of the GWA. This is accomplished by re-scaling the hourly wind speeds from ERA-5 to match the long-term average wind speeds from GWA for each cell, as shown in Equation (2). The wind speeds for 150 m and 200 m altitudes are determined by using the long-term average wind speeds for those altitudes $a$.

$$u_{t,a,l} = u_{t,100m,l}^{\text{ERA-5}} \times \frac{\bar{u}_{a,l}^{\text{GWA3}}}{\bar{u}_{100m,l}^{\text{ERA-5}}}, \ \forall t,a,l \in \mathcal{T},\mathcal{A},\mathcal{L} \tag{2}$$

$u_{t,100m,l}^{\text{ERA-5}}$ is the wind speed for hour $t$ at 100 m altitude in the $1 \times 1$ km cell $l$, $\bar{u}_{a,l}^{\text{GWA3}}$ is the long-term average wind speed at altitude $a$ in cell $l$ and $\bar{u}_{100m,l}^{\text{ERA-5}}$ is the annual average wind speed at 100 m in cell $l$.

Wind speed time series are then combined with the multi-turbine power curves from Figure 2 to generate the generation time series for each turbine design and resource class in every region. This procedure is illustrated in Figure 3.

**TABLE 2** Wind resource classes used in this work and their IEC counterparts according to IEC 61 400-1.[20]

| | Onshore | | Offshore | |
|---|---|---|---|---|
| | Annual average wind speed (m/s) | IEC equivalent | Annual average wind speed (m/s) | IEC equivalent |
| Class 5 | >8 | I/II | >9 | I |
| Class 4 | 7–8 | II/III | 8–9 | I/II |
| Class 3 | 6–7 | III | 7–8 | II/III |
| Class 2 | 5–6 | undefined | 6–7 | III |
| Class 1 | <5 | undefined | <6 | undefined |

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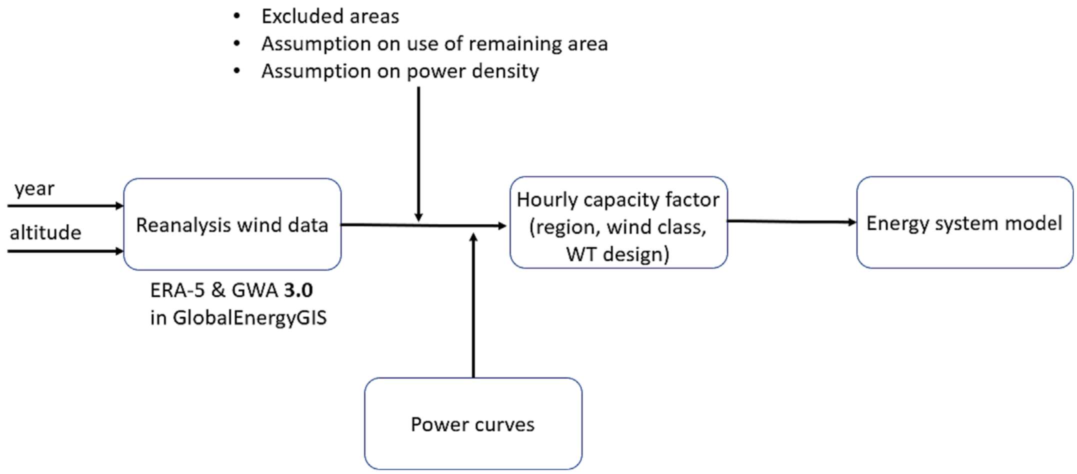


**FIGURE 3** Overview of the wind data processing method.

The available land resource ($L_{r,c}$) in each region $r$ and resource class $c$ in square kilometres is determined by summing the cells within each region according to resource class. $a_{l,c}$ is the area of cell $l$, corresponding to $1\,\text{km}^2$. It is assumed that 10% of the resulting area can be used for wind power development onshore and 33% offshore, represented by $f_c$ in Equation (3).

$$L_{r,c} = \sum_{l \in \mathcal{L}_r} a_{l,c} \times f_c, \ \forall r,c \in \mathcal{R},\mathcal{C} \tag{3}$$

This is the available land resource provided to the energy system model, which combined with the capacity density sets a constraint for potential capacity investments. The baseline capacity densities are 5 MW/km$^2$ and 8 MW/km$^2$ for onshore and offshore, respectively, which is the usual range used for energy system modelling purposes.[1] For turbine designs with lower SP ratings, the capacity densities are lower than the baseline (see Table 1).

## 2.3 | The energy system model

The energy system model used is a linear investment and dispatch optimization model. A full mathematical formulation can be found in Appendix A of Göransson et al[22] and Appendix C of Johansson and Göransson.[2] The modelled time period encompasses 1 year, corresponding to Year 2050, with a time-step resolution of 1 h. The regional scope is northern Europe, constituting 13 inter-connected regions, as illustrated in Figure S4.3. The model employs a greenfield approach and includes expected new demands for electricity and hydrogen until Year 2050. Given the Year 2050 time-frame, only technologies without direct CO2 emissions are included. Apart from the wind turbine designs, the number of included technologies is 15. Depending on their cost and technical properties, generation ($g$) from these technologies either compete with wind power generation or complement it. A list of the technologies with their cost and technical parameters is presented in Table S4.8 found in Appendix S4. The model considers the cycling constraints imposed on thermal power plants in the forms of start-up costs, start-up times, and minimum load levels.

The total system cost that is being minimized is shown in Equation (4). It consists of the annual sum of investment costs of technologies ($C_p^{\text{inv}}$), their operating costs ($C_p^{\text{OPEX}}$) as well as start-up ($C_p^{\text{start}}$) and part-load costs ($C_p^{\text{part}}$) of thermal generators.

$$\min \sum_{r \in \mathcal{R}} \left( \sum_{p \in \mathcal{P}} i_{p,r} \times C_p^{\text{inv}} + \sum_{p,t \in \mathcal{P},\mathcal{T}} g_{p,r,t} \times C_p^{\text{OPEX}} + \sum_{p,t \in \mathcal{P},\mathcal{T}} g_{p,r,t}^{\text{start}} \times C_p^{\text{start}} + \sum_{p,t \in \mathcal{P},\mathcal{T}} \left( g_{p,r,t}^{\text{part}} - g_{p,r,t} \right) \times C_p^{\text{part}} \right) \tag{4}$$

The optimization is subject to several constraints, the most relevant of which are described below. The energy balance expressed in Equation (5) mandates that the total generation ($g$) plus net-discharge ($s$) from energy storages (ESS) minus net-export ($r$) of electricity meets the demand ($D$) for each region ($r$) and increment of time ($t$).

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$$\sum_{p \in \mathcal{P}} g_{p,r,t} + \sum_{p \in \mathcal{P}^{\mathrm{ESS}}} \left( s_{p,r,t}^{\mathrm{discharge}} - s_{p,r,t}^{\mathrm{charge}} \right) - \sum_{r' \in \mathcal{R}} x_{p,r,r',t} \le D_{r,t}, \ \forall r,t \in \mathcal{R},\mathcal{T} \tag{5}$$

Generators ($p$) can only produce electricity and energy storage units charge and discharge electricity at the capacity of their investment ($i$), as shown in Equations (6) and (7).

$$g_{p,r,t} \le i_{p,r}, \ \forall p \notin \mathcal{P}^{\mathrm{VRE}}, r,t \in \mathcal{R},\mathcal{T} \tag{6}$$

$$s_{p,r,t}^{\mathrm{charge}} \le i_{p,r}, \ s_{p,r,t}^{\mathrm{discharge}} \le i_{p,r}, \ \forall p \in \mathcal{P}^{\mathrm{ESS}}, r,t \in \mathcal{R},\mathcal{T} \tag{7}$$

Wind power and solar PV are divided into resource classes ($c$) that determine the normalized generation profile ($P$) and available land resource ($L$). Generation from these varying renewables (VRE) is limited by the installed capacity and weather driven generation profile, as shown in Equation (8).

$$g_{p,r,t,c} \le i_{p,r,c} \times P_{p,r,t,c}, \ \forall p,r,t,c \in \mathcal{P}^{\mathrm{VRE}}, \mathcal{R}, \mathcal{T}, \mathcal{C} \tag{8}$$

Installed capacities for wind power are limited by the available land resource ($L$) in each resource class ($c$) and the turbine design's capacity density ($Cd$), according to Equation (9).

$$\sum_{p \in \mathcal{P}^{\mathrm{VRE}}} \left( \frac{i_{p,r,c}}{Cd_p} \right) \le L_{r,c}, \ \forall p,r,c \in \mathcal{P}^{\mathrm{VRE}}, \mathcal{R}, \mathcal{C} \tag{9}$$

Charging of energy storages and the storage of electricity over time is described in its generalized form in Equation (10). In the case of hydrogen, $s_{p,r,t}^{\mathrm{discharge}}$ is equivalent to the hourly hydrogen demand of region $r$ and $s_{p,r,t}^{\mathrm{charge}}$ corresponds to the electrolyzer output.

$$soc_{p,r,t+1} \le soc_{p,r,t} + \eta_p^{\mathrm{ESS}} s_{p,r,t}^{\mathrm{charge}} - s_{p,r,t}^{\mathrm{discharge}}, \ \forall p \in \mathcal{P}^{\mathrm{ESS}}, r,t \in \mathcal{R},\mathcal{T} \tag{10}$$

Cycling limitations of generators are included as described in Equation (11), mandating that part load level of non-VRE generators be between the active generation ($g$) and installed capacity.

$$g_{p,r,t} \le g_{p,r,t}^{\mathrm{part}} \le i_{p,r}, \ \forall p \notin \mathcal{P}^{\mathrm{VRE}}, r,t \in \mathcal{R},\mathcal{T} \tag{11}$$

**Table S3.**7 in Appendix S3 offers an explanation of the sets, variables and parameters used.

## 2.4 | Scenarios

Four energy system scenarios are investigated to delineate the driving forces behind wind turbine selection.

In the Free scenario, all turbine designs are made available to the model. The COE scenario serves as a comparative basis for a system that comprises only those turbines that have the lowest cost of energy (COE). Therefore, only the turbine designs with the lowest COE per region and resource class are available to the model. An overview of these designs is shown in Table S1.1. Any difference in wind turbine composition between the COE and Free scenarios is indicative of the presence of other driving forces for turbine selection.

The Flex scenarios assess the impacts on the wind turbine selection of flexibility measures in the forms of grid-scale battery storage, hydrogen storage units and transmission capacity expansions. The inclusion of flexibility measures has previously been emphasized as an important component when investigating the relevance of wind turbines with low SP ratings in energy systems.[3,23] Table 3 provides an overview of the four scenarios and the differences between them.

The rationale for including both non-flexible and flexible scenarios is to be able to assess whether (1) adapted wind turbine design can aid in managing variations and (2) how it interacts with previously established flexibility measures. The chosen flexibility measures play different roles and provide a solid basis for comparison. Batteries are a cost-effective means of managing frequent variations of low duration and high amplitude. Hydrogen storage units address variations of longer duration, albeit of smaller amplitude. Trade in electricity via transmission systems supports

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**TABLE 3** Overview of investigated scenarios.

| | Free | COE | Free + Flex | COE + Flex |
|---|---|---|---|---|
| Wind turbines | All | Only lowest COE[a] | All | Only lowest COE[a] |
| Flexibility measures | None | None | Batteries | Batteries |
| | | | Hydrogen storage | Hydrogen storage |
| | | | Transmission expansion | Transmission expansion |

[a]For every resource class and region there is one turbine design with the lowest COE. The reader is directed to Table S1.1 in Appendix S1 for this information.

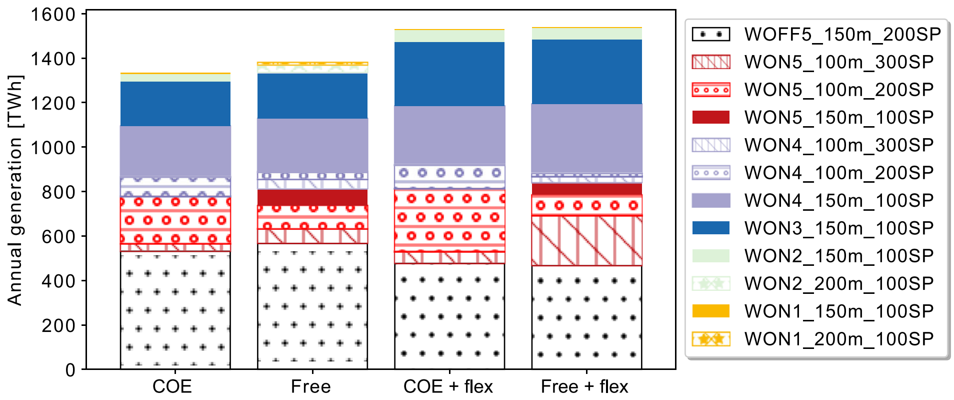


**FIGURE 4** Annual levels of electricity generation from wind power in northern Europe for the *Free*, *COE*, *Free + Flex* and *COE + Flex* scenarios. The fill or hashing correspond to the SP ratings (dashed, 300SP; dash-circle, 200SP; filled, 100SP); black-dotted is used for offshore turbines and star-hash for turbines with tall towers. The colour corresponds to the wind resource class.

the geographic smoothing effect of wind power production within an interconnected electricity system. Combining multiple flexibility measures that address different types of variations is a strategy that is used to achieve more-cost-efficient systems.[2]

### 2.5 | Metric for assessing variations

In the context of electricity systems that have high shares of renewables, variations typically refer to changes in the net load time series. Net load, which is defined as the difference between the electricity load and level of generation from intermittent renewable sources, provides information about the nature of the demand that the dispatchable generation sources and flexibility measures of the system have to satisfy.

To visualize such variations, a metric developed by Göransson and colleagues[24] is used. The net load is categorized according to its duration, amplitude and occurrence frequency. Duration refers to the consecutive number of hours during which a net load of a certain amplitude is prevalent. Amplitude corresponds to the level or value of the net load. The occurrence frequency reflects how often a variation in net load with a certain amplitude and duration occurs during the investigated time period. The net load can then be plotted using these three properties, facilitating comparisons between scenarios. Classification of the net load in this manner also enables the identification of appropriate flexibility measures to be used. The exact calculation procedure for the variables can be found in the publication by Göransson.[24] The metric is not part of the optimization problem itself, rather it is used to quantify final variations in net load and explain the difference caused by the turbine types.

## 3 | RESULTS

Figure 4 shows the annual electricity generation levels from wind turbines in northern Europe, broken down according to turbine design. The label WON or WOFF indicates that the turbine is placed onshore or offshore, respectively. The succeeding number indicates the wind resource class, with a higher number corresponding to better wind conditions. The last element of the turbine designation relates to the turbine tower height (in metres) and the SP (in W/m$^2$). This means that a WON5_100m_300SP turbine has a turbine design with 100 m tower height and a specific power of 300 W/m$^2$ and is subject to hourly wind speed data and land resource constraints of resource class five. WON4_100m_300SP

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represents the same turbine design but instead subject to data of resource class four. An alternative illustration of the same data can be viewed in Tables S1.1–S1.4 presented in Appendix S1.

Each scenario contains a mix of turbine designs. Some designs are common across all four scenarios, albeit different in terms of the share of annual generation, for example, WON5_100m_300SP and WON5_100m_200SP. Other designs show up only in certain scenarios (WON4_100m_300SP, WON5_150m_100SP, WON2_200m_100SP, etc.).

The fact that the cost-optimal wind turbine mix in the *Free* scenario differs from that in the *COE* scenario indicates that driving forces other than cost of energy are influencing the turbine design. The *Free* scenarios feature, on aggregate, higher levels of generation from the 100 SP and 300 SP turbines, whereas the level of generation from 200 SP turbines is lower.

Overall, the total annual level of generation from varying renewables is increased by free turbine choice (Free 2.6% higher than COE). The availability of other flexibility measures in the *Flex* scenarios increases by a further 11% the annual level of generation from VRE in both scenarios. This is expected, as flexibility measures facilitate higher shares of wind power by increasing the load during high wind periods and/or by reducing the load during low wind periods. In the *COE* + *flex* scenario, investments in hydrogen storage amount to 982 GWh and 734 GWh for battery storage. In the Free + flex scenario, the investments are 991 GWh and 695 GWh respectively.

Table 4 presents the key indicators for the four scenarios. The cost-optimal capacities and levels of generation of the electricity system are presented in Figures S2.1 and S2.2 in Appendix S2.

The scenarios with free choice in terms of turbine design have lower total system costs, regardless of the availability of flexibility measures. The reduction is to a large extent the result of increased generation from wind power, which reduces the total fuel and investment costs for the thermal power plants that it replaces. *Flex* scenarios have lower costs because they allow for investments in variation management strategies (VMS), which increase the cost-efficient utilization of the system resources. The aggregate data presented in Figure 4 and Table 4 facilitate the identification of major changes. However, to acquire detailed explanations for these changes, we need to investigate them at a higher geographical resolution. Figures 5,6 and 7 show the annual generation of each turbine technology in each scenario, with sub-plots broken down according to region.

The lack of difference in turbine design choice between the *Free* and *COE* scenarios in Figure 5 suggests that, in some regions, the lowest COE turbine designs are the cost-optimal ones also from a systems perspective. In other regions, there are different choices of scenarios, suggesting the presence of other driving forces, which vary by region. The findings indicate three driving forces for the choice of wind turbine design: (1) cost of electricity generation; (2) amount of electricity generated per square kilometre of ground area; and (3) variation pattern of the electricity generation. The following sections will explore each driving force and relate them to the results presented in Figures 5–7. An alternative presentation of the same underlying data can be found in Tables S1.1–S1.6 in Appendix S1.

## 3.1 | Rules and driving forces for turbine selection

### 3.1.1 | Rules for turbine selection

The general approach to determining the cost-optimal turbine for each region and resource class is to use the lowest cost of electricity generation (COE). For wind resource Class 3 or lower, this always results in a 100SP turbine design being the cost-optimal choice. The difference in full-load hours (FLH) between the 100SP and 200SP/300SP turbines in these resource classes is substantial, and it offsets the higher specific investment cost of 100SP turbines compared to the 200/300SP turbines. Figures 5–7 show that turbines with 300SP and 200SP are only cost-optimal at onshore sites that have good wind resources (Classes 5 and 4). In these classes factors other than COE emerge. These can broadly be categorized into two driving forces: (1) maximizing the generation from the given land area and (2) improving the production pattern of wind power by using a turbine design with a preferable generation profile.

**TABLE 4** Summary of the scenarios with key indicators.

| Scenario | | COE | Free | COE + Flex | Free + Flex |
|---|---|---|---|---|---|
| Total system cost, annualized | $GEUR_{2015}/year$ | 89.7 | 88.5 | 73.3 | 72.6 |
| Utilized onshore wind potential | $km^2$ | 83,000 | 87,200 | 106,000 | 109,000 |
| Utilized offshore wind potential | $km^2$ | 6530 | 6930 | 5140 | 5060 |
| Share of generation from VRE | % | 74.3 | 76.2 | 84.5 | 84.6 |
| Aggregate wind power capacity | GW | 302 | 308 | 325 | 329 |

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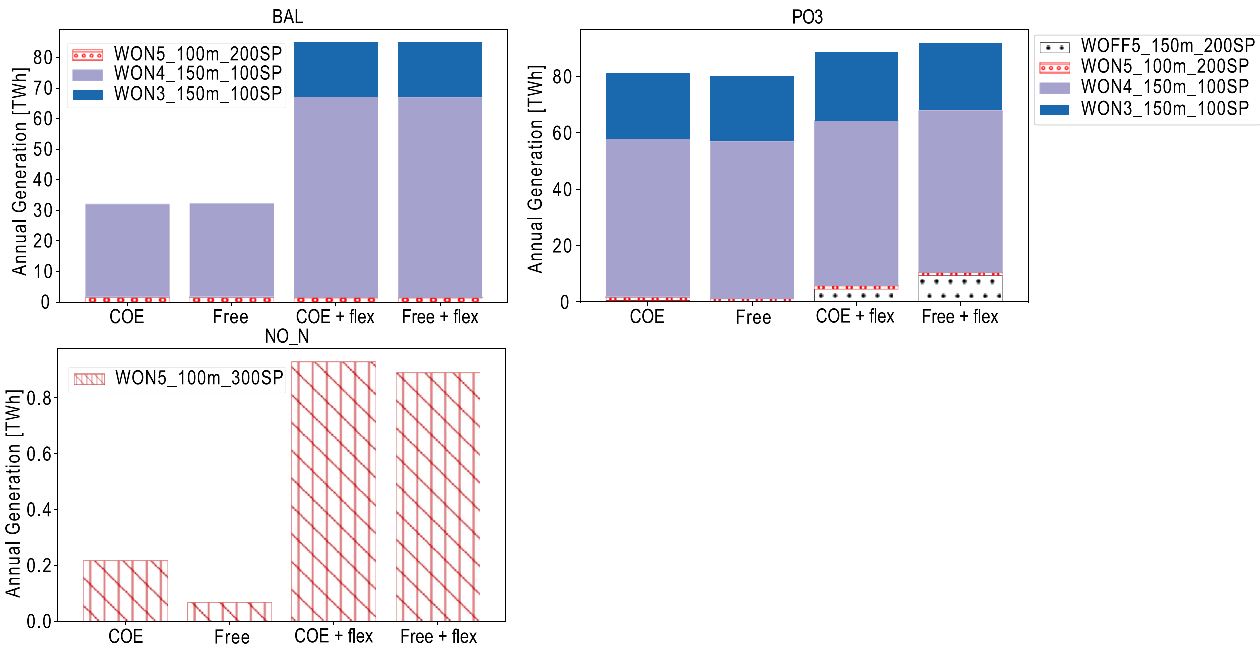


**FIGURE 5** Annual levels of electricity generation from wind power for the *Free*, *COE*, *Free* + *Flex* and *COE* + *Flex* scenarios in regions where lowest cost of electricity is the driving force for turbine selection.

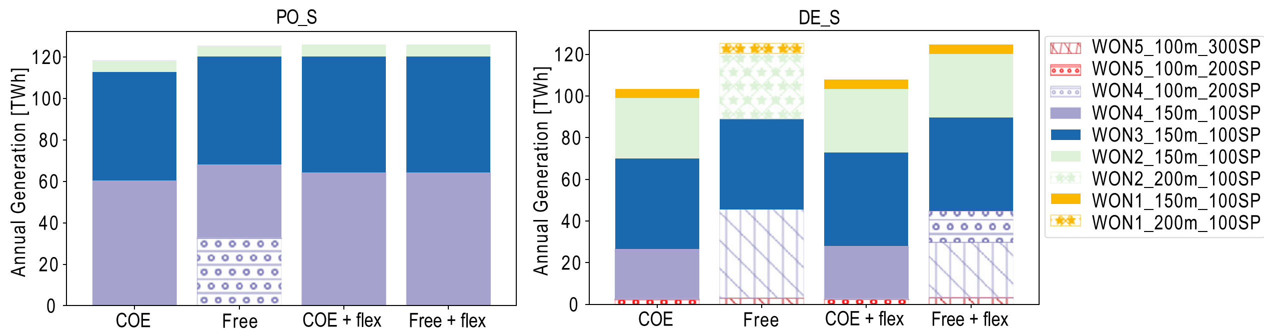


**FIGURE 6** Annual levels of electricity generation from wind power for the *Free*, *COE*, *Free* + *Flex* and *COE* + *Flex* scenarios in regions where annual wind production per land area is the driving force for turbine selection.

### 3.1.2 | Driving force 1: Cost of electricity generation

In the BAL and PO3 regions (see Figure 5), the choice of turbine design is very similar between the *Free* and *COE* scenarios, both with and without flexibility measures. This implies that the turbine designs with the lowest COE are also the cost-optimal ones from a system perspective. This also applies to the NO_N region for the *Free* + *flex* and *COE* + *flex* scenarios. Historically, this has been the primary driving force for wind power investments and turbine design. Table S1.1 in Appendix S1 shows the turbine design per region and resource class with the lowest cost for electricity generation.

### 3.1.3 | Driving force 2: Annual wind production per land area

Figure 6 shows that in the DE_S and PO_S regions, higher SP turbines enter the cost-optimal solution in the *Free* scenario, as compared to the *COE* scenario.

The turbine design with the lowest COE in resource Class 5 for DE_S is 200SP. The design for the cost-optimal solution is 300SP, which is the turbine design that has the highest level of generation per land area. The same applies to resource Class 4 in DE_S. Here, the lowest COE turbine design is 100SP, whereas the cost-optimal design is 300SP. The higher SP turbine facilitates more installed capacity on the available land. As

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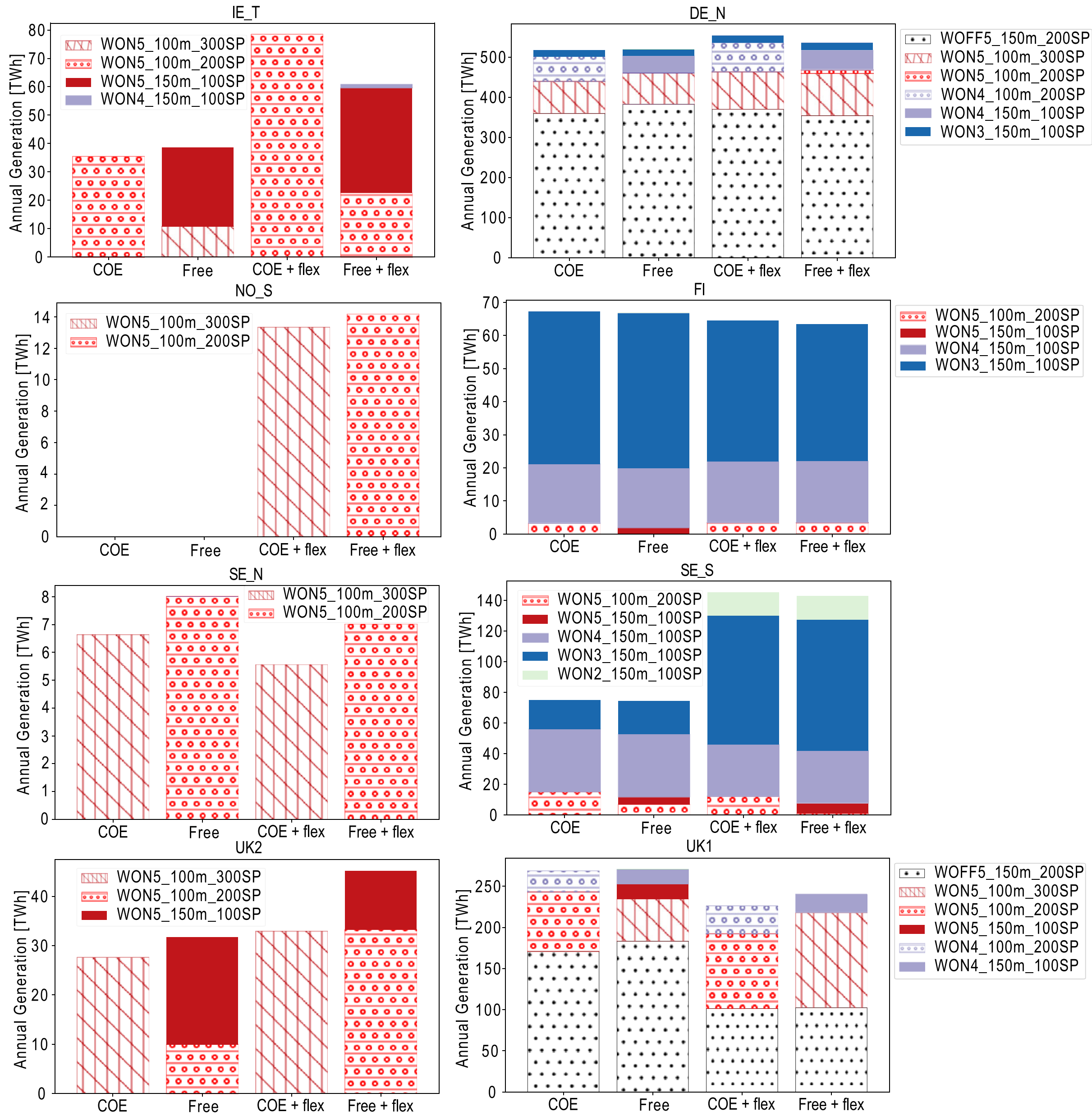


**FIGURE 7** Annual levels of electricity generation from wind power for the *Free*, *COE*, *Free + Flex* and *COE + Flex* scenarios in regions where variation in wind generation profiles is the driving force for turbine selection.

a result, the total level of generation from wind power is increased in both resource classes, thereby reducing the need for other, more costly bulk generation sources. This is reflected in a reduction of the nuclear power capacity by 3.4 GW (−31%) and a reduction of the annual generation from nuclear power by 27 TWh (−31%) in the DE_S region.

The trend of deviating from the lowest COE turbine design does not hold true for resource Class 3 and lower classes. The value linked to increasing annual generation from wind by choosing a turbine design with higher generation per land area is smaller than the associated increase in generation costs for low resource classes. For resource Class 3 and lower classes, the difference in FLH between the COE turbine design (100SP) and the 200SP/300SP turbines becomes significant, which increases the difference in generation costs.

In the PO_S region, the turbine with the lowest COE in resource Class 4 is 100SP. The cost-optimal solution features a combination of 100SP and 200SP turbine designs in the *Free* scenario. The 200SP turbine has a higher level of generation per land area, facilitating higher levels of wind power generation, thereby replacing more-costly nuclear power. The resulting reduction in nuclear power capacity is 1.5 GW (−48%), and the reduction in annual level of generation from nuclear power is 11 TWh (−46%). The mix of two turbine designs in the same resource class indicates that a saturation point is reached, such that any additional capacity added by either turbine would not be cost-optimal. In this case, the competitiveness is with respect to nuclear power generation, and any additional 200SP capacity would not contribute to reducing investments in nuclear

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power. This is likely due to the number of low wind speed hours during which the 200SP output is lower than that of the 100SP turbine, requiring generation from sources other than wind power.

These two examples suggest that it can be cost-efficient to maximize the amount of generated electricity per land area. The required land area per installed capacity is higher for turbine designs with lower SP ratings, as the increased rotor size results in increased distances between the turbines. Higher SP turbine designs are more cost-efficient compared to the lower SP alternatives when the area available for wind power generation is small relative to the total electricity demand. In such a situation, additional wind generation would displace other more costly bulk electricity generation sources, such as nuclear power.

Another important observation is the role of tall towers. Increasing the height of the tower essentially increases the wind speed that acts on the rotor. The effect is similar to improving the location's resource class. In this sense, higher turbine towers represent a costly way to increase the amount of generated electricity per land area. Tall towers are only cost-optimal in the DE_S region, both in Class 1 and Class 2. In resource Class 1, it is cost-optimal to invest in taller towers because the difference in annual generation level between the 100SP turbines with regular towers and taller towers becomes significant (ca. 10%). The turbines in the DE_S region have the lowest FLH of any turbines in resource Class 2, so the benefit of taller towers is greater.

### 3.1.4 | Driving force 3: Variation in wind generation profiles

As shown in Figure 7, a mix of non-COE turbine designs is found to be cost-optimal in the IE_T, UK1 and UK2 regions.

Turbines with different SP ratings complement each other in terms of their production patterns at different wind speed regions. Low SP turbines produce power at low wind speeds when high SP turbines are unable to do so. However, low SP turbines have earlier cut-out of production at high wind speeds, at which point high SP turbines are at their maximum level of generation. The abrupt cut-out behaviour creates variations in the generation profiles of low SP turbines during high wind speed events that need to be managed. This is mainly true for locations with good wind resources that frequently reach very high wind speeds ( ≥ 15 m/s). Therefore, a combination of different SP turbines can create the most cost-efficient system, and the selection of turbines to be included depends on the system context.

In the IE_T region, the turbine design with the lowest COE in resource Class 5 is 200SP. The cost-optimal turbine choice is a mix of 100SP and 300SP. The mix creates a generation profile from wind power that requires less additional management of the resulting variations in load by other generation technologies. This is illustrated in Figure 8, which shows the generation profiles for the lowest COE turbine (200SP) and the cost-optimal mix (100 and 300SP) in the IE_T region.

During high wind speed events, the 100SP and 200SP turbines will start to cut out and the 300SP turbines will continue producing at the rated power. In addition, the 100SP turbine will generate electricity at very low wind speeds when both the 200SP and 300SP turbines have low

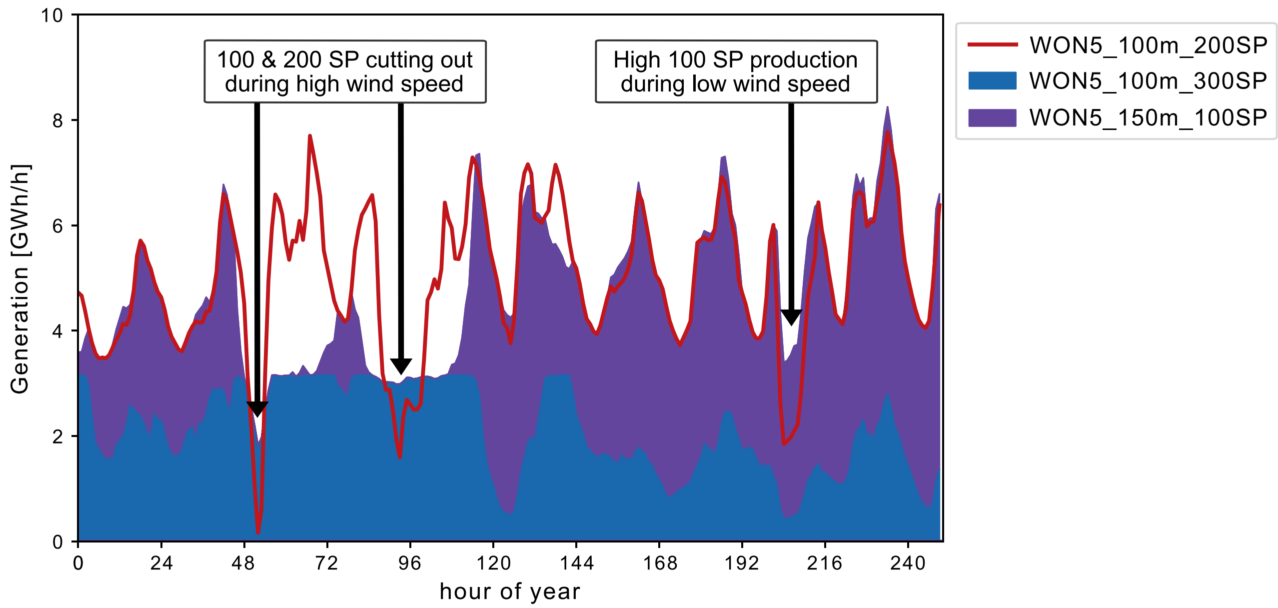


**FIGURE 8** Generation profile for the lowest COE turbine (200SP, red) and the cost-optimal mix (100 and 300SP, purple and blue) in IE_T region. The combination of 100 and 300SP reduces the variations in generation throughout the year. The purpose is not to increase annual generation or to maximize the amount of generated electricity per land area.

or very low levels of production. In this way, the combination of 100SP and 300SP turbines does not mimic the profile of 200SP, but rather compensates for the weaknesses of the individual turbine designs.

How exactly the nature of the electricity net-load variations for IE_T are changed as a result of this is shown in Figure 9.

There is a reduction in the frequency of occurrences and amplitude of variations with positive amplitude when all turbine designs are available, as shown by arrow 3 in Figure 9. Variations with large negative amplitudes of short-to-medium duration are reduced, exemplified by ellipse A and the path of arrow 1. The duration of variations with small negative amplitude is reduced, as indicated by arrow 2. Figure 8 illustrates how the mix of 100SP and 300SP turbines can lead to higher levels of generation during low-wind-speed events, which translates to a reduction in high net load. Similarly, during high-wind-speed events, wind production is lower, leading to a reduction of the variations with large negative net load. Overall, the range of the characteristics of the variations is smaller in the Free scenario compared to the *COE* scenario.

In the UK2 region, the 300SP turbine offers the lowest COE in resource Class 5, while a mix of 100SP and 200SP turbines is cost-optimal. The 200SP turbine makes up for the low cut-out wind speed of the 100SP turbine, which provides value during low-wind-speed periods, especially when hydropower is running at full capacity. During these periods, the requirement for peak generation is reduced. As a result, the open cycle gas turbine capacity and generation decrease significantly.

In UK2, the 300SP turbine offers the lowest COE in resource class 5, while a mix of 100SP and 200SP is cost-optimal. The 200SP turbine makes up for the low cut-out wind speed of the 100SP turbine, which provides value during low wind periods, especially when hydropower is running at full capacity. During these periods the requirements for peak generation is reduced. Open cycle gas turbine capacity and generation decrease significantly as a result.

Figure 10 shows the variations for the UK2 region, exhibiting notable differences between the *Free* and *COE* scenarios.

When all turbine designs are available, variations of large negative amplitude are removed, as highlighted by ellipse B in Figure 10. The occurrence of variations with low positive amplitude and short duration are significantly increased, visualized with ellipse A. In general, the range of variations is smaller and more-concentrated around low durations and low-to-medium levels of amplitude. This shift is illustrated by arrows 1 and 2.

These findings suggest that the choice of turbine type has an impact on the variations in net electricity load. Whether it is cost-optimal to forego the turbine with the lowest cost for electricity generation depends on the electricity system context. In regions with low availability of other VMS, such as UK2 and IE_T, the total system cost is reduced as a result of choosing the turbine with the most-suitable variability characteristics.

In the UK1 region, 200SP is the turbine with the lowest COE in resource Class 5, whereas the cost-optimal choice is a mix of the 100SP and 300SP turbines. The 300SP turbine provides value during hours of very high wind speeds, when the other turbine designs are not generating due to cut-out. It is most cost-efficient to obtain this characteristic in resource Class 5 and compensate for the lack of generation during low-wind-speed hours with 100SP turbines in Classes 4 and 5. The combination of wind turbines with different SP ratings results in a reduced need for CCGT capacity and generation in both the IE_T and UK1 regions. This can be attributed to higher levels of wind power generation during both very high and very low wind speed events.

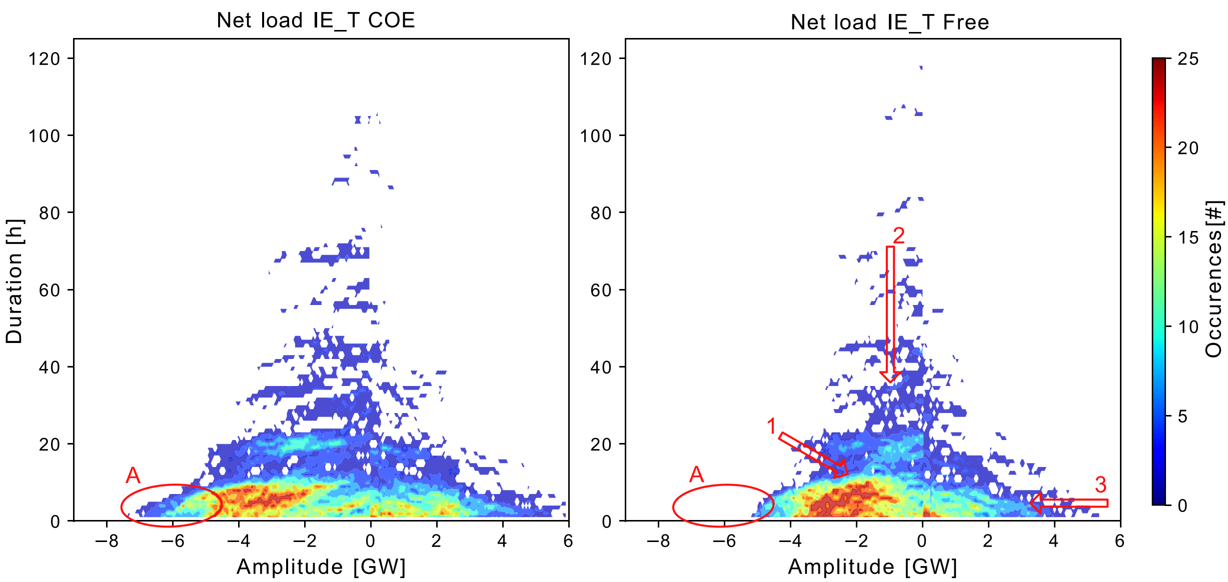


**FIGURE 9** Variation characteristics of the net electricity load in the IE_T region for the *Free* and *COE* scenarios. Arrows 1–3 and ellipse A indicate how the variations have changed between the *COE* and *Free* scenario.

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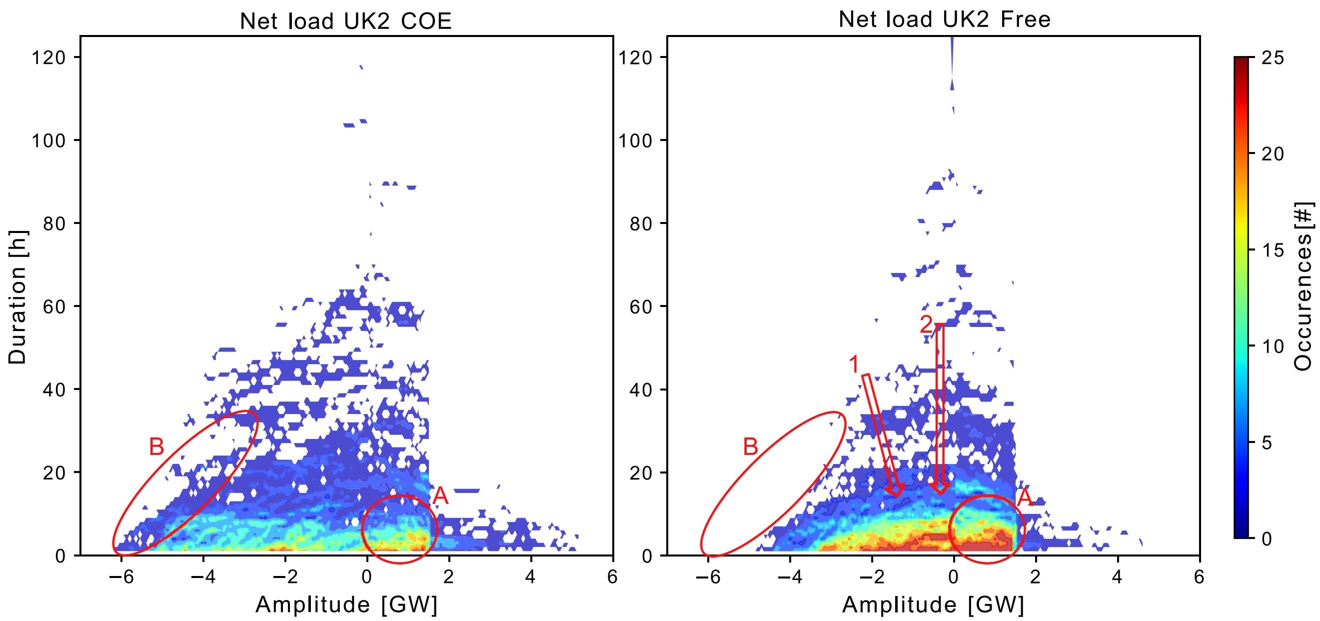


**FIGURE 10** Variation characteristics of the net electricity load in the UK2 region for the *Free* and *COE* scenarios. Arrows 1 and 2 and ellipses A and B indicate how the variations have changed between the *COE* and *Free* scenario.

In the SE_S region, the turbine with the lowest COE in Class 5 is 200SP. The optimal solution features a mix of 200SP and 100SP turbines. With the addition of 100SP turbines, wind generation is increased during medium-to-low wind speed events, during which hydropower typically is running at full capacity. As a result, the limited hydropower resource can instead be used to reduce the required CCGT capacity and generation. Hydropower also makes up for the earlier cut-out during high-wind-speed events.

In the FI and SE_N regions, similar generation profile-related effects can be observed in wind Class 5, albeit to a lesser degree and with weaker impact on the surrounding system. In both cases, the difference in LCOE between the COE turbine and the cost-optimal turbine is very small. This implies that the required cost reduction provided by the cost-optimal turbine only needs to be very small to trigger a change in turbine type.

In the DE_N region, the 200SP turbine has the lowest COE in resource Class 4, whereas the 100SP turbine is cost-optimal. Compared to Class 5, the 100SP turbines have much more FLH in Class 4 than the 200SP turbine. Therefore, a higher SP turbine is used in Class 5, which is complemented by a 100SP turbine in Class 4, so as to improve the generation profile across the resource classes. Similar to what is seen for other regions, the result is a noticeable reduction in the required CCGT capacity and generation.

## 3.2 | Effects of flexibility measures

Figure 4 shows that the cost-optimal wind turbine mix differs between the *Free* + *Flex* and *COE* + *Flex* scenarios. In the Flex scenarios, investments in flexibility measures in the forms of hydrogen storage, new transmission lines, and grid scale batteries are allowed. Despite these technologies being available, the cost-optimal turbine choice is in some cases still different from the turbine with the lowest COE. Similar to the cases without flexibility measures, the *Free* + *Flex* scenarios feature, on aggregate, more generation from 100SP and 300SP turbines compared to the *COE* + *Flex* scenario, whereas generation from 200SP turbines is reduced. The difference occurs mainly in resource Classes 4 and 5. The fact that this behaviour is present in the *Flex* scenarios indicates that the adapted generation profile provides a benefit in terms of variation management that the other flexibility measures are unable to provide, at least at the same cost.

The addition of flexibility measures increases wind generation from resource Classes 3 and 2 while reducing generation offshore. Sites with poor wind resources become cost-competitive with respect to other generation sources when flexibility measures are available. The increased generation on land reduces the need for more-expensive generation offshore.

As shown in Table 4, the total cost of the northern European electricity system is reduced by 1% in the *Free* + *Flex* scenario compared to the *COE* + *Flex* scenario. This reduction mainly stems from lower investments in transmission capacity in the British and Irish Isles (UK1, UK2 and IE_T) and in the DE_N and DE_S clusters. The need for peak electricity generation in the form of open cycle gas turbines is reduced, which is reflected in lower fuel costs.

Figure 11 shows the cost-optimal mix of turbines for the British and Irish Isles.

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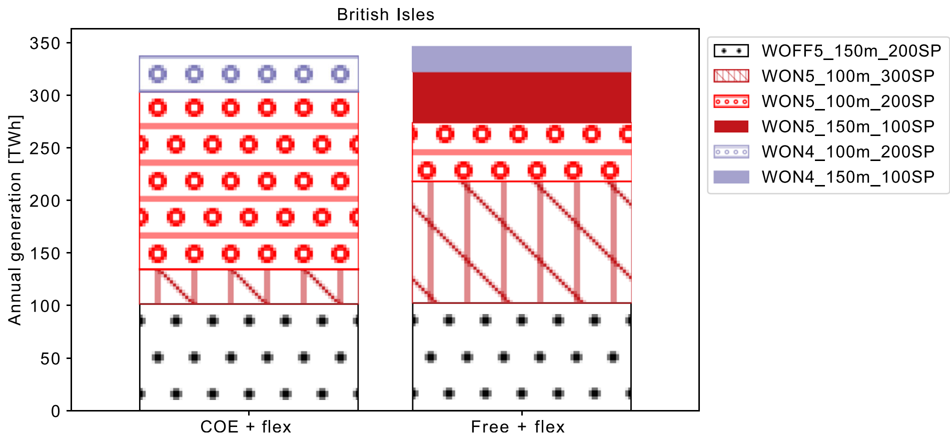


**FIGURE 11** Annual levels of electricity generation from wind power in the British and Irish Isles for the *COE* + *Flex* and *Free* + *Flex* scenarios.

**TABLE 5** Energy storage investments in select regions and total for northern Europe.

| | **Free + Flex** | | | **COE + Flex** | | |
|---|---|---|---|---|---|---|
| | **IE_T**<br>**UK1**<br>**UK2** | **SE_N**<br>**SE_S**<br>**FI** | **DE_N**<br>**DE_S**<br>**TOTAL** | **IE_T**<br>**UK1**<br>**UK2** | **SE_N**<br>**SE_S**<br>**FI** | **DE_N**<br>**DE_S**<br>**TOTAL** |
| Stationary batteries | 31.4 \| 4.11 | - | 180 \| 13.6 | 94.0 \| 9.23 | - | 195 \| 14.4 |
| | 196 \| 22.7 | 15.3 \| 3.07 | 124 \| 21.9 | 156 \| 20.9 | 18.3 \| 3.63 | 111 \| 19.7 |
| | 19.6 \| 2.29 | 14.6 \| 2.26 | 695 \| 85.9 | 23.4 \| 2.60 | 13.5 \| 2.17 | 734 \| 88.7 |
| H2-storage with electrolyzer | - | 17.7 \| 0.72 | 262 \| 10.8 | - | 18.9 \| 0.69 | 270 \| 10.9 |
| | 193 \| 3.58 | 23.2 \| 0.54 | 353 \| 9.74 | 199 \| 3.52 | 22.0 \| 0.55 | 326 \| 9.44 |
| | - | 25.9 \| 0.88 | 991 \| 32.5 | - | 25.6 \| 0.87 | 982 \| 32.2 |

*Note*: Values shown are Energy storage capacity (GWh) | Power capacity (GW).

It can be seen that the lowest COE turbine mix comprises 200SP turbines with some 300SP turbines. The cost-optimal mix features a significantly larger share of 300SP and some 100SP turbines. Offshore generation is largely unaffected and in both scenarios the available area is not used fully. Total generation from wind power increases slightly (3%) with free turbine choice. The difference in turbine choice between the *Free* + *Flex* and *COE* + *Flex* scenarios can be explained by an improved generation profile from wind, similar to what is shown in Figure 8. The resulting variations in net electricity load can be managed in a more cost-efficient manner, which is reflected in lower fuel costs for gas turbines. The reduced investment in transmission capacity in the *Free* + *Flex* scenario can also be attributed to this effect. Less overall transmission capacity is required as a result of the changed nature of the variations. This can be valuable considering the long lead time needed for building high-voltage transmission lines in reality.

### 3.2.1 | Competition with other technologies that manage variations

It has been established that in systems with few other means for managing variations, the choice of wind turbine type can serve as a VMS by changing the characteristics of the variations that are created from wind power in the first place. The question remains as to whether this option is cost-optimal relative to other VMS, such as batteries or hydrogen storage. Table 5 shows the installed energy and power capacities of stationary batteries and hydrogen storage units for selected regions in the *Free* + *Flex* and *COE* + *Flex* scenarios.

As shown in Table 5, lower total battery storage and power capacity levels are needed in the *Free* + *Flex* scenario than in the *COE* + *Flex* scenario. The largest reductions are seen in regions IE_T and UK2. In the case of IE_T, the storage and power capacities of the batteries are reduced by 67% and 55%, respectively. This indicates that fewer batteries are needed to manage the variations found in the system. The affected regions have good wind resources and limited access to no-cost VMS, such as reservoir hydropower. In the SE_N region, it is not cost-efficient to invest in battery storage, since the region has sufficient existing variation management capacity in the form of hydropower.

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Investments in hydrogen storage systems and electrolyzers exhibit only small changes. Flexible hydrogen production has a positive amplitude when considered in terms of net electricity load. As shown in Figures 9 and 10, turbine design mostly affects the negative amplitudes. Turbine design and flexible hydrogen production, therefore, do not compete with respect to managing variations.

The UK1 region sees an increase in battery investments in the *Free* + *Flex* scenario. The turbine choice in UK1 and the surrounding regions (IE_T and UK2) reduces the duration and increases the frequency of occurrences of variations in net load with positive amplitude. The resulting variations can be managed in a cost effective manner by batteries. Consequently, batteries displace some peaking gas turbines, which previously managed such variations.

Some regions (e.g., FI and DE_S) exhibit an increase in investment in energy storage in the *Free* + *Flex* scenario compared with the *COE* + *Flex* scenario. A reason for this could be the increase in the share of renewables when it comes to total electricity generation. An increase in the share of renewables typically increases the demand for and, thereby, investments in VMS, such as energy storage units.

As indicated in Figure 4, even with flexibility from other sources, it is not cost-optimal to invest exclusively in the turbines with lowest COE. The 200SP and 100SP wind turbines offer a benefit to the system that cannot be provided as cost-effectively by other VMS (energy storage units and transmission capacity investments). That wind makes up most of the electricity generation in these scenarios means that any change in the type of wind turbine will have a significant impact on the remaining system composition.

## 3.3 | Sensitivity to battery and turbine costs

Whether or not it is cost-optimal to use wind turbine design to manage variations in the electricity system depends on the available alternatives and their associated costs. To assess the robustness of the findings, the investment cost of stationary batteries was varied. The regions IE_T and UK2 are of interest, as they represent cases in which turbine design is actively used as a means to change the nature of variations in electricity generation.

Figure 12 shows the annual generation from wind power for the IE_T region, broken down according to turbine configuration. The scenarios feature reductions in battery costs of 20% and 40%, respectively. Increased wind turbine costs for the 100SP turbines are also featured.

Overall, the selection of turbines and general shares of generation are very similar across the four scenarios. A lower cost for batteries reduces slightly the generation from wind power in the IE_T region. This is likely a result of increased generation from solar PV, the diurnal variations of which are complemented well by batteries. WON5_100m_200SP is primarily affected by this. When investment costs are increased for the 100SP turbines, generation from offshore turbines decreases. As they are more expensive, 100SP turbines receive reduced levels of investment, and this means that there are instead higher levels of investment in the 200SP and 300SP turbines in the same resource class, resulting in displacement of the offshore turbines. The increase in generation from these turbines is clearly visible.

Figure 13 shows the annual generation levels from wind power for the UK2 region, broken down according to turbine configuration.

Similarly, the selection of turbines is identical, and it is the amount of generation that differs between the scenarios. In contrast to IE_T, the reduced cost of batteries does not decrease the overall level of generation from wind power in UK2. Batteries and 200SP turbines in UK1 displace

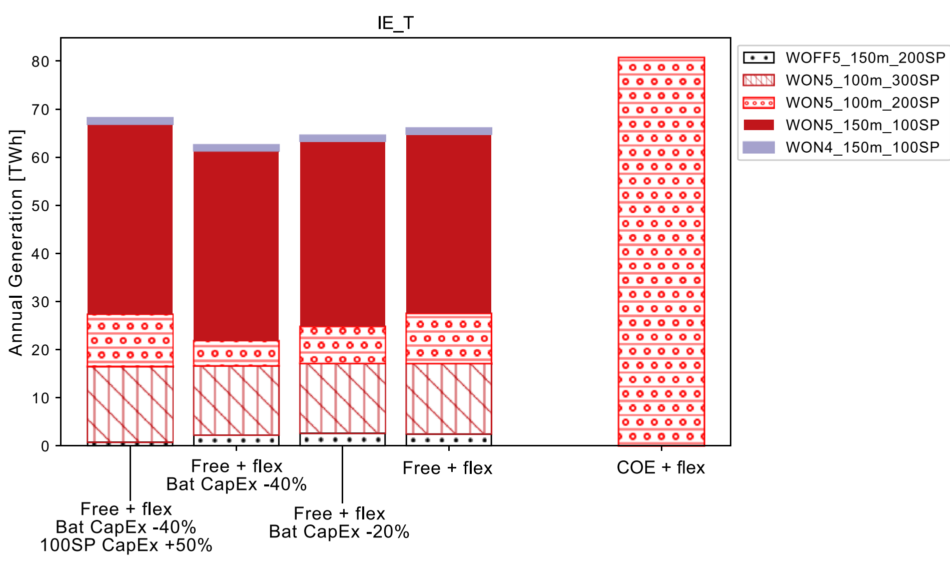


**FIGURE 12** Annual levels of electricity generation from wind power in IE_T for the sensitivity analysis scenarios.

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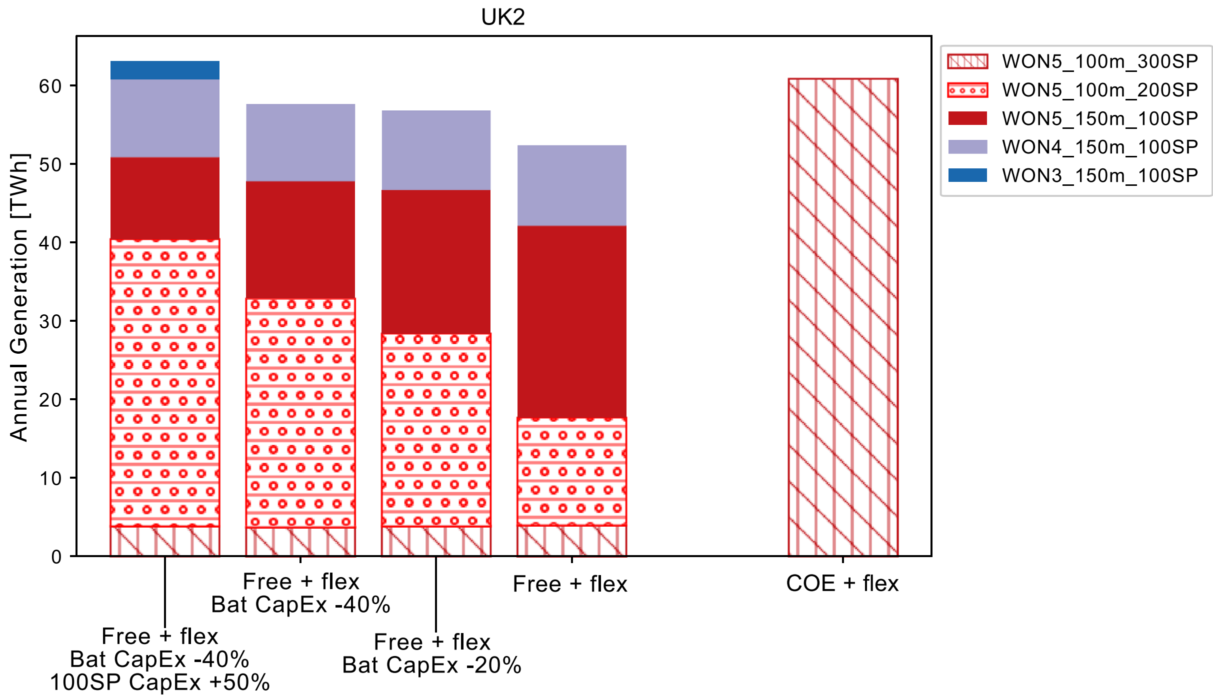


**FIGURE 13** Annual levels of electricity generation from wind power in UK2 for the sensitivity analysis scenarios.

100SP turbines in wind resource Class 5. The higher cost of 100SP turbines leads to a decrease in the level of generation from said turbines, which is replaced by generation from the 200SP turbines.

# 4 | DISCUSSION

## 4.1 | Model and data limitations

The model is not designed to predict the exact compositions of future electricity systems but is instead used to illustrate the driving forces and interaction effects between technologies, in a setting that is reflective of a highly renewable energy system. The model features a high temporal resolution and a comprehensive technology portfolio, and it includes flexibility measures that provide different types of VMS, which are needed to assess properly energy systems that have high shares of intermittent renewable generation. The wind power implementation aims to account for the possible technological development of wind turbines in the future. The resulting turbine designs are sufficiently heterogeneous to provide alternatives for each of the driving forces.

Turbulence and variations on a sub-hourly scale are not captured by the energy system model applied in this work. For the aggregated scale used in the model, these effects are likely largely diminished due to geographical smoothing. It is unclear as to whether the turbine designs would be impacted differently by sub-hourly variations. Turbines with larger rotors have a larger rotating mass, although they also have an increased swept area that is exposed to changes in wind conditions.

While the extent of wake losses associated with large-scale deployment of wind remains to be fully understood, wakes can be thought of as wind speed deficits and increased turbulence of the down-wind flow. Wake effects in this work are implemented as internal losses that reduce the incoming energy by a fixed percentage. In reality, the wake loss is dependent on the wind direction, wind speed and the wind farm layout. Depending on the turbine spacing and wind conditions losses can reach values double or triple of the 12.5% assumed in this work, with size of the wind farm being a decisive factor.[25] As shown by Feng and Shen,[26] optimization of the wind farm layout can however mitigate these effects to some extent and also improve the variability of generation. In the context of this work, implementing a wind speed-dependent wake loss term could improve the description and would lower the losses at lower wind speeds while increasing the losses at higher wind speeds. It is not clear whether wake effects will affect all turbine designs equally.

To capture the effects of higher wind speeds with increasing altitude, the 100 m hourly wind speeds from ERA-5 are re-scaled to match the annual average wind speeds from GWA for different altitudes. Previous research has shown that re-scaling ERA-5 with GWA yields good results.[27] The effect on annual generation is deemed to be weak, since the average wind speed is the same. However, it is likely that the pattern

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of wind variations differs slightly between different altitudes. Divergence and convergence of wind speeds occur at different altitudes.[28] These behaviours reflect the wind speed, with convergence at low wind speeds, meaning that the wind speeds are similar over a range of altitudes that are relevant for wind power production, and divergence at higher wind speeds. The employed method, which does not account for convergence and divergence, therefore, over-estimates the wind speeds for altitudes of 150 m and 200 m at low wind speeds and under-estimates them for high wind speeds.

The present work does not explicitly consider other aspects concerning the design of wind turbines, such as structural loads and aerodynamic performance. Currently, the 300SP and 200SP turbines are being installed globally, while no commercial 100SP turbines have been installed to date. However, conceptual work is being carried out on designs that match the cost and technical properties of the turbine used in this work.[29] There is ongoing research on the logistical and technical challenges linked to large rotor turbines, and multiple viable solutions have been proposed.[30] Whether or not these turbines will be developed further depends on whether the benefits that they offer can be fully realized in practice.

The wind turbine cost model and energy system model do not consider power system stability, local grid capacity limitations, varying grid connection requirements between countries, provision of ancillary services, and grid-forming functionalities, such as inertia responses and frequency reserves. While these factors may create new driving forces and require additional investments, their impacts on the total system cost and likely to be weak and unlikely to impact significantly the findings.[31]

The cost predictions for increasing rotor diameters and turbine tower heights are subject to significant uncertainty. Recent years have seen a significant increase in cost of materials and labour.[32] The components of a turbine, and therefore the turbine designs presented in this work, are impacted differently by this cost increase depending on their supply chain and the required materials. Beiter and colleagues[33] point out that costs also are influenced by macroeconomic factors, making their development very difficult to forecast.

There are other benefits and drawbacks associated with low SP turbine designs that are not included and assessed in this work, such as the impacts on forecast error and the robustness of wind turbine designs in terms of how sensitive they are to inter-annual variations in wind power.

### 4.2 | Results discussion

The findings presented here indicate that the most cost-effective wind turbine fleet encompasses a combination of designs, such as those found in the IE_T, UK_1 and UK_2 regions, even in the same resource class. When it comes to combinations of wind turbine designs, various questions need to be answered. How will profit-maximizing actors behave? Will they be able to take advantage of the potential benefits of mixed designs? How will non- COE driving forces affect the behaviours of these actors?

Each actor may initially seek to maximize generation on the limited land area, favouring turbine designs with high SP ratings. As the share of wind power in an electricity system increases, prices are affected by wind generation, which strengthens the profile driving force. In this case, it will be valuable to generate electricity during low-wind-speed hours, since there are only designs with high SP ratings in the system. Designs with low SP ratings will then be favoured, as they have higher levels of generation during low-wind-speed hours.

Wind farms are typically homogeneous, meaning that all the turbines are identical. Therefore, a mix of turbine designs within the same farm is not expected. However, the wind turbine fleet in a region is not homogeneous in terms of SP ratings, resulting in a mix of power curves and production profiles. Furthermore, fleet performance changes over time as old turbines are retired and replaced with modern designs. As a result, the cost-optimal design for new investments may change over time.

Hirth and Müller have suggested that, at least to some extent, advanced turbine designs compete with other flexibility measures.[3] While that study did not explicitly compare systems with only high or low SP designs, the findings show that there is value associated with adapting the turbine design and, thereby, modulating the variations in wind power generation. Counter-intuitively, the improvement does not always need to be achieved by turbines with lower SP ratings, as seen in the cases of IE_T and UK2.

Previous research[3,23] has shown that turbines with low SP ratings retain their value factor to a greater extent as the wind share increases, as compared to turbines with high SP ratings. However, this does not mean that low SP turbines are always the cost-optimal choice due to their low capacity densities. Moreover, the variations produced by these turbines are not necessarily easier to manage. The wind speed range within which variations predominantly occur is shifted towards lower wind speeds, and new variations are created due to more frequent cut-outs, which happen at lower wind speeds. Figure 8 shows that combining high SP and low SP turbines can help to mitigate the drawbacks of each design. It is unclear as to whether actors will strategically employ a mix of turbine designs or if the mix will occur organically.

Cost-optimal turbine design is sensitive to wind deployment potential, as limiting the resource strengthens the area driving force and increasingly renders high SP turbine designs cost-optimal. The wind resource potential in the present work is in line with those in other studies.[1] Weak social acceptance can limit the available potential for wind power production. Finding a "good" value to ensure social acceptance of onshore wind power is difficult in energy system modelling. Low levels of social acceptance would result in higher investments in offshore wind power and, potentially, in nuclear power.

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## 5 | CONCLUSIONS

The following driving forces for turbine design selection are identified: (1) lowest cost of electricity generation; (2) highest level of electricity generation per land area; and (3) improved generation profile of wind power. Lowest cost of electricity generation is the most-important driving force for regions with poor wind resources. High-level of electricity generation per land area is the primary driver in regions with high electricity demands relative to the resource potential for wind power production.

In regions with good wind resources and limited availability of variation management, it is cost-efficient to reduce the variability of wind power production by adapting the turbine design. This is accomplished at the lowest cost by altering the rotor diameter rather than hub height. The use of a combination of designs in the same region results in a generation profile that is more robust during very low and very high wind speed events.

Reducing the variability of wind power by adapting turbine design is cost-optimal even when VMS is available in the form of batteries, hydrogen storage, and transmission system expansion.

### AUTHOR CONTRIBUTIONS

**Henrik Hodel:** Conceptualization; methodology; formal analysis; data curation; writing – original draft; visualization. **Lisa Göransson:** Conceptualization; methodology; writing – review and editing; supervision. **Peiyuan Chen:** Conceptualization; writing – review and editing; supervision. **Ola Carlson:** Conceptualization; writing – review and editing; supervision.

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### CONFLICT OF INTEREST STATEMENT

The authors declare no potential conflict of interests.

### PEER REVIEW

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### DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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## SUPPORTING INFORMATION

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