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# System-friendly wind power☆
# How advanced wind turbine design can increase the economic value of electricity generated through wind power

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ABSTRACT

Previous studies find that the economic value of electricity (USD/MWh) generated by wind power drops with increasing market share. Different measures can help mitigate the value drop, including electricity storage, flexible conventional plants, expansion of transmission, and demand response. This study assesses another option: a change in design of wind power plants. "Advanced" wind turbines that are higher and have a larger rotor compared to rated capacity (lower specific rating) generate electricity more constantly than "classical" turbines. Recent years have witnessed a significant shift towards such advanced technology. Our model-based analysis for Northwestern Europe shows that such design can substantially increase the spot market value of generated electricity. At a 30% penetration rate, the value of 1 MWh of electricity generated from a fleet of advanced turbines is estimated to be 15% higher than the value of 1 MWh from classical turbines. The additional value is large, whether compared to wind generation costs, to the value drop, or to the effect of alternative measures such as electricity storage. Extensive sensitivity tests indicate that this finding is remarkably robust. The increase in bulk power value is not the only advantage of advanced turbines: additional benefits might accrue from reduced costs for power grids and balancing services. To fully realize this potential, power markets and support policies need to be appropriately designed and signal scarcity investors.
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## 1. Introduction: market value and the "silent revolution"

This study addresses the economic value of electricity generated by wind power in wholesale power markets. Wind power and other resources such as solar or marine energy that are variable in nature, are collectively referred to as variable renewable energy sources (VRE) hereafter. The variability of VRE generators affects the economics of these technologies. At high penetration, variability typically reduces the market value of VRE generation — such that on average 1 MWh from wind power is worth less than 1 MWh from a thermal or hydro power station. At a given moment in time, electricity from any source has, of course, the same value. VRE technologies have a lower (average) market value because they tend to produce disproportionately during times when the electricity price is low. This has sometimes been referred to as the "self-cannibalization effect", because it is the abundance of VRE itself that depresses market prices during periods of high resource availability.[1]

"Market value" is defined here as the weighted average market price, where the hourly generation of the respective technologies serves as the weighting factor. This market value is the average realized price for energy on wholesale spot markets. This corresponds to the marginal socio-economic value of electricity, if markets failures are absent: if the market value of wind power is USD 80 per MWh, 1 MWh has an economic benefit to society of USD 80. To the extent that externalities are

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[1] Note that this is different from the "merit-order effect" as introduced by Sensfuß (2007). Sensfuß refers to the depression of the average electricity price (base price) during a period of rapid introduction of renewable-based (or any other) power generation.

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present however (e.g. lack of pricing carbon emissions), the market prices will not fully reflect value to society.

Previous studies (Grubb, 1991; Lamont, 2008; Joskow, 2011; Mills and Wiser, 2012; Gowrisankaran et al., 2014, among others) have shown that the value declines with VRE penetration. This "value drop" can be quite substantial, such that electricity from wind power can be worth 20–50% less than electricity from a constant source at a 30% wind penetration rate in energy terms (Hirth, 2013). However, estimates vary widely depending on the system studied and assumptions made. The low market value is a challenge to long-term competitiveness of variable resources, potentially endangering power system transformation and decarbonization.

Several countries now accommodate VRE shares of 15% to 44% in annual generation, including Denmark, Spain, Portugal, Ireland, Lithuania, and Germany.[2] Sub-national power systems with high VRE shares include Eastern Inner Mongolia (China) and Texas (U.S.). The IEA (2015a) projects that medium-term growth will continue at a rapid pace in many parts of the world. Long-term models forecast that by 2050 VRE shares will need to be several times higher than today (Fischedick et al., 2011; Luderer et al., 2014; Knopf et al., 2013; IEA, 2013, 2015b). The value drop is already a pressing issue for a number of regions today and will eventually become so globally. Exploring ways to ease the value loss matters today and will matter more in the future.

There are many ways to better integrate VRE into power systems and thereby mitigate the value drop (Holttinen et al., 2011; IEA, 2014). Such measures have been called "mitigation measures" (Mills and Wiser, 2014) or "integration options" (Hirth and Ueckerdt, 2013a). They include making electricity demand more responsive to available supply, increasing storage capacity, expanding interconnector capacity, or upgrading hydropower and thermal plants to improve operational flexibility. The design of power markets and policies, as well as system operation, has a critical role in providing appropriate incentives and making flexibility available in practice. Several recent studies assess the impact of such measures on VRE market value (Mills and Wiser, 2014; Pudlik et al., 2014; Gilmore et al., 2015; Hirth, 2015a). Above and beyond these options to make power systems more "wind-friendly", VRE technologies themselves can be designed and deployed in a more "system-friendly" way and thereby the value of their output is increased.

System friendly deployment may be achieved by spreading generators across large geographic areas or deploying a well-chosen mix of technologies. Another possibility lies in the technical design of VRE generators themselves. Wind power turbines can be re-designed to produce electricity more constantly. Solar modules can be installed such that some face East and West, smoothing overall output during the course of the day. Less variable output will reduce costs in the rest of the power system, especially at high VRE penetration rates. The main idea behind system-friendly generator design is to consider system integration effects, rather than minimize generation costs alone.

Wind turbine technology has evolved substantially during the past decade. The "low wind speed" turbines that have entered the market are taller and have a larger rotor-to-generator ratio (a lower specific rating per area swept by the rotor). These turbines capture more energy at low wind speeds. This advancement in wind turbine technology has been described as a "silent revolution" (Chabot, 2013). In the United States, the specific rating of newly installed turbines has dropped from 400 W/m$^2$ to 250 W/m$^2$ during the past 15 years (Wiser and Bolinger, 2015). With a lower specific rating, electricity is generated more constantly, which can potentially increase the economic value of the electricity, or, equivalently, have better system integration properties. Because of this and for brevity, we label such wind turbines as "advanced".[3]

Traditional remuneration schemes such as feed-in tariffs provide little or no incentive for such design because they tend to reimburse the supplier irrespective of when and where the power is generated — in contrast to wholesale power markets, where prices fluctuate. Consequently, current deployment patterns of wind technology provide a poor benchmark for assessing the possible benefit of system-friendly plant design. In order to overcome this problem, this study contrasts turbine designs that are adapted to different wind-speed environments and investigates the extent to which the use of a particular design across all locations leads to significant differences in the economic value of the electricity produced.

The contribution of this paper to the literature is twofold. First, it provides a comprehensive account of the different system-level benefits of advanced wind power. Second, it presents model-based evidence of the gain in spot market value at different penetration rates. In short, we try to answer the question "What is the additional value of advanced turbine design compared to classical turbine design?"

## 2. The various benefits of system-friendly renewables: a taxonomy

This study assesses the economic benefits of system-friendly VRE deployment strategies. There are a variety of such strategies with various potential benefits.

### *2.1. Types of system-friendly VRE deployment strategies*

Several strategies exist to design and deploy VRE differently that might help mitigate the drop in value, including:

- *Geographic location of VRE*: because the availability of any given renewable resource varies significantly across large geographic areas, plants can be dispersed throughout the power system to flatten aggregate generation profiles ("geographical smoothing").
- *Diversification of VRE mix*: the mix of onshore wind, offshore wind, solar power and other VRE resources can be optimized to flatten aggregated VRE output (in Europe, for example, mixing wind and solar power in appropriate proportions reduces seasonal variability).
- *Design of solar generators*: PV modules can be oriented towards the east and the west, or track the sun to flatten solar generation profiles, or simply point westwards to better match demand peaks ("advanced solar").
- *Design of wind turbines*: turbines can be constructed with taller towers and lower specific ratings to flatten wind generation profiles ("advanced wind turbines").[4]

We refer to these options as system-friendly deployment strategies, because they help "improve" the structure of residual load (such that residual load is less costly to serve). All these strategies aim to shift VRE production towards times when electricity is needed, thereby increasing the economic value of the electricity produced. Note that other publications use "system-friendly" to refer to ancillary service capabilities such as voltage support and fault ride-through.

There is significant literature on the system benefits of the first three strategies outlined above: on geographical smoothing (Göransson and Johnsson, 2013; Consentec & Fraunhofer IWES, 2013; Lewis, 2010; Brown and Rowlands, 2009; Mills and Wiser, 2010, 2014; GE Energy, 2010; EnerNex, 2011; Grothe and Schnieders, 2011; Mono et al., 2014; Fraunhofer IWES, 2015), optimizing the VRE mix (Schaber, 2014; Heide et al., 2010, 2011; Tafarte et al., 2014; Lund, 2005), and advanced solar power (Hummon et al., 2013; Fraunhofer ISE, 2014; Hartner et al., 2015; Waldmann and Bhandari, 2014; Zipp and Lukits, 2014; Tröster and Schmidt, 2012; Tafarte et al., 2014; Fraunhofer

[2] http://www.iea.org/statistics/relatedsurveys/monthlyelectricitysurvey/.

[3] We use "advanced wind power" and "advanced wind turbines", as well as "advanced technology" and "advanced design" interchangeably.

[4] McInerney and Bunn (2015) discuss a variant: system-friendly wind park, as opposed to wind turbine, design. They consider the case of "overbuilding" parks in the sense of installing a larger aggregate nameplate capacity than the capacity of the grid connection. As a result, the capacity factor of the connection increases.

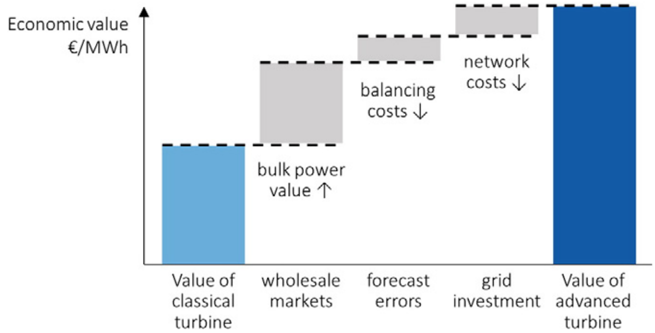


**Fig. 1.** Potential benefits of advanced VRE technology design, illustrated by a wind turbine. Our findings indicate that at high penetration, advanced wind turbines have a higher bulk power value, and cause lower balancing and grid costs. Under certain circumstances however, such as low penetration rates, the value of advanced turbines can be lower than that of classical turbines.

IWES, 2015). However, while there is wide agreement that advanced wind plant design has potential system benefits, there is only limited evidence for the *size* of such benefits.[5] This is the gap this study aims to fill.

### 2.2. Types of benefits

Advanced wind turbine design has a number of potential benefits, including (i) higher revenues from wholesale power markets (increased bulk power value), (ii) reduced forecast errors, and (iii) reduced grid costs (Fig. 1). Bulk power value comprises revenues from energy (spot) markets and capacity markets, if present; in the terminology of Mills and Wiser (2012), this is the sum of energy value and capacity value. We focus our analysis on bulk power value.

The principal objective of our modeling exercise is to develop a better understanding of the extent to which advanced wind power can boost the long-term bulk power value of wind power. It focuses on one VRE technology (onshore wind), one system-friendly deployment strategy (advanced wind power) and one type of benefit (increased bulk power value). Other benefits are assessed based on a literature review (Section 5), and costs are discussed based on interviews conducted with manufacturers (Section 6). System-friendly solar power is discussed in Appendix A.

## 3. Methodology: metric, model, data

This study measures the additional benefit of advanced technologies as the increase in average market value (USD/MWh) during the course of a year, where "increase" is the difference between the market value of an advanced generation profile and that of a classical generation profile, rather than a development over time. VRE market values are estimated using the European power market model EMMA while generation profiles for wind power are constructed from re-analysis weather data. Metrics, model, and data processing are discussed in turn.

### 3.1. Metrics used to quantify the benefits of advanced technologies

Different metrics have been used to evaluate the system effects of renewables, including curtailment (Bode, 2013), storage requirements (Heide et al., 2010), excess energy volumes (Tafarte et al., 2014), and investor return (McInerney and Bunn, 2015). This study employs a welfare-economic perspective and assesses advanced renewables in terms of *additional market value*. The additional value is identified by comparing the market value of advanced design to that of classical design at a given penetration rate (throughout the document, penetration rate always refers to average yearly penetration in energy terms).

Market value differences arise from differences in bulk power value, balancing costs, and grid costs. Focusing on the first item, we follow Joskow (2011) and define market value here as the weighted average wholesale electricity price, where the hourly generation of the respective technologies serves as the weighting factor. This definition excludes income from support schemes. Hence, it represents the average price of 1 MWh of electricity generated by a certain generator type during one year.[6] Formally,

$$\textit{Wind market value} = \frac{\sum_{t=1}^{8760} w_t \cdot p_t}{\sum_{t=1}^{8760} w_t},$$

where $p_t$ is the hourly spot price and $w_t$ is the electricity generated from wind power in hour $t$. In hours of high wind speeds, the additional supply of electricity from wind turbines depresses the price below the level it would otherwise have been. This price drop is greater, of course, when larger amounts of wind power are installed, a phenomenon that has been described as the "self-cannibalization effect" (a dramatic term for the simple consequence of increased supply). As a consequence, the market value of wind power declines with its market share.

Of course, at a given moment in time, electricity from any type of wind turbine is the same. The value of advanced technologies is higher, because they can generate the same amount of electricity more evenly during the year, alleviating the self-cannibalization effect; more electricity is generated at times when its price is higher. Put differently, advanced turbines spill some wind energy when it is very windy (because the capacity of the generator is reached), but these are times when electricity prices are, in any case, low, hence the economic cost of spillage is small.

The market value not only matters for investors, but has a fundamental socio-economic interpretation. Under perfect and complete markets, the increase in market value corresponds to the premium that consumers are willing to pay for generation from advanced VRE plants: if the market value of wind power is USD 80 per MWh, 1 MWh has an economic benefit to society of USD 80. Hence, the market value is identical to the marginal economic value (Mills and Wiser, 2012). Hirth et al. (2015) discuss various sources of market imperfections in real-world power markets.

We determine the market value at the long-term economic equilibrium of the power market, given a certain amount of wind power. The thermal capacity mix as well as the amount of interconnectors and electricity storage is chosen by the model, leading to moderately more interconnector capacity than observed today. For each penetration rate, the long-term economic equilibrium is determined twice: once with classical design and once with advanced design. The difference between the two cases in wind market value is reported as the additional market value of advanced design, or "delta".

### 3.2. Economic model: EMMA

The analysis is based on results from the European Electricity Market Model (EMMA), which has previously been used to study the economics of wind and solar power.[7] EMMA is a techno-economic model of the

[5] We draw on the existing literature on advanced (low wind-speed) turbine technology, but these studies provide only little discussion on the benefits for the power system or the effect on wind market value (Molly, 2011, 2012, 2014; IEA, 2013; de Vries, 2013; Gipe, 2013; Wiser and Bolinger, 2015; Fraunhofer IWES, 2013).

[6] Alternatively, one could define the value in terms of capacity (per MW). A rational investor takes an investment decision if the expected revenue ($/MW) is higher than expected costs ($/MW), or, equivalently, if the expected revenue ($/MWh) is higher than expected cots ($/MWh). Costs are predominantly summarized as "levelized costs of electricity" / "levelized energy costs", in other words, in energy terms (€/MWh). To be comparable with these costs, we report the value in energy terms.

[7] Examples include the peer-reviewed publications by Hirth (2013, 2015a, 2015b) and Hirth and Ueckerdt (2013b), as well as Hirth (submitted for publication) and Hirth and Steckel (submitted for publication).

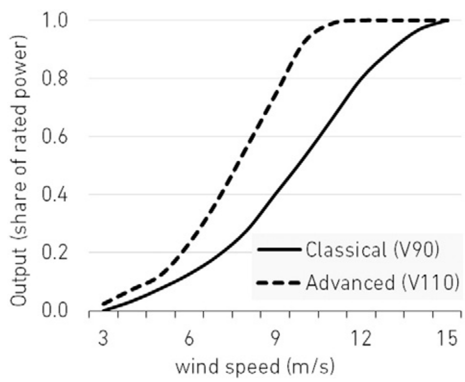


**Fig. 2.** Power curves of a "classical" (Vestas V90) and an "advanced" turbine (Vestas V110).

integrated Northwestern European power system, covering France, Benelux, Germany, and Poland. It models both dispatch of and investment in power plants, minimizing total costs with respect to investment, production and trade decisions under a large set of technical constraints. It calculates the long-term optima (equilibria) and estimates the corresponding capacity mix as well as hourly prices, generation, and cross-border trade for each market area. It models a primarily thermal power system; results might be quite different in a hydro-dominated system.[8] In economic terms, it is a partial equilibrium model of the wholesale electricity market with a focus on the supply side. The model is linear, deterministic, and solved in hourly time steps for one year. Details on EMMA, including open source code and input data, can be found on the following website: www.neon-energie.de/emma/. Crucial parameters are documented in Appendix C.

### 3.3. Wind generation profile

In the context of this study, the most important model input is the hour-by-hour time series of wind power generation. Advanced wind turbines are modeled combining two features: (i) a taller tower than classical turbine design; and (ii) a larger rotor-to-generator ratio (lower specific rating). As winds tend to be more constant at greater heights above ground, and a lower specific rating implies relatively more output at intermediate wind speeds, both features tend to make output more constant. In this sense advanced wind turbines are "less intermittent" than classical turbines.

Wind speed data were taken from ERA-Interim weather data. ERA-Interim[9] is a re-analysis weather model that provides wind speeds in three-hour granularity at a spatial resolution of 0.75° × 0.75°. Given that the primary focus of the study is not an assessment of balancing requirements the main quantitative trends are expected to be robust at this temporal resolution. We used wind speeds at 90 m and 120 m above ground, respectively. All locations with an average wind speed of > 6 m/s as measured at the respective hub height were selected as appropriate sites for wind power. We used the meteorological year 2009 and provide sensitivity results for all years between 2008 and 2012.

Wind speeds were transformed into electricity generation data using different power curves. Power curves of different turbine models were extracted from public manufacturers' documents provided on their websites. All power curves used stem from turbines that are currently commercially available, except the sensitivity in Section 4.7. A lower specific rating results in a different power curve (Fig. 2). As a classical turbine, we use the power curve of a Vestas V90–3.0 MW, evaluated at a hub height of 90 m. As an advanced turbine, we use the power curve of a Vestas V110–2.0 MW, evaluated at 120 m. Table 1 provides key technical characteristics of these turbines. While the V90 model is designed for wind classes IEC IA and IIA, the V110 turbine is designed for wind class IEC IIIA. Hence in reality the latter turbine cannot simply be installed on any wind site. We use its power curve as an example of a turbine with a low specific rating. Section 4.2 provides sensitivity analyses based on different power curves.

**Table 1**
Technological characteristics of classical and advanced turbines.

| | Classical | Advanced |
|---|---|---|
| Evaluated at hub height (m) | 90 | 120 |
| Specific power rating (W/m$^2$) | 472 | 211 |
| Output intermediate wind speed (8 m/s) [% rated capacity] | 30% | 60% |
| Cut-in wind speed (m/s) | 3.5 | 3.0 |
| Wind speed to reach rated capacity (m/s) | 15 | 11.5 |

Classical turbine: Vestas V90–3.0 MW; advanced turbine: Vestas V110–2.0 MW.

As a baseline for comparison, it is assumed that the same technology is deployed at all sites. Hence we compare a scenario in which high wind speed turbines are installed everywhere to a scenario where low wind speed turbines are installed everywhere. Given today's deployment patterns, this represents a hypothetical scenario. However, there is already a trend observable in the market towards deploying low wind speed technology at higher wind speed sites (Wiser and Bolinger, 2015; Fraunhofer IWES, 2013). In general, specific ratings tend to decrease across resources sites. Furthermore, analysts have so far considered less contrasting evolutions (Chabot, 2014), revealing more limited decreases in specific ratings and thus more limited, though substantial, increases in annual average capacity factors.

Both higher towers and lower specific ratings tend to increase annual average capacity factors. With our data, we find the capacity factor almost doubles (Fig. 3). Hence, at the same penetration rate in energy terms, advanced turbines require only half the installed capacity than that of classical turbines. In the chosen example of V90–3 MW versus V110–2 MW, this means 25% fewer machines.

The output of a fleet of advanced turbines fluctuates less (Fig. 4) and is more evenly distributed throughout the year (Fig. 5) than that of a fleet of classical turbines. Theory predicts that reduced variation of output will lead to a more stable market value (Hirth and Radebach, 2016).

To verify that the classical wind profile is representative for the status quo, we evaluated it with observed German spot price data from 2006 to 12, and compared the result to the market value derived from wind generation patterns reported by system operators. The numbers coincide well. The resulting value factor deviates on average only 0.5% from the value factor calculated for observed wind generation patterns reported by system operators (Table 2).

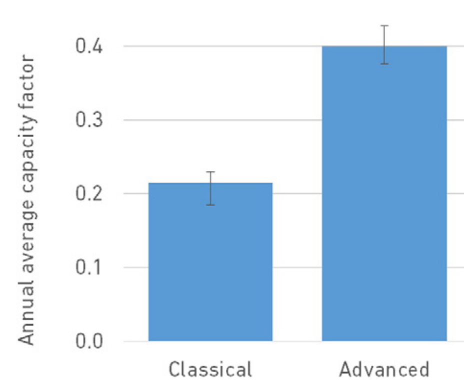


**Fig. 3.** Annual average capacity factors, as derived from these power curves, using data from the weather year 2009 in Germany. Error bars show variation 2008–12. The classical capacity factor of 0.21 corresponds to 1880 full load hours (FLH), the advanced capacity factor of 0.4 to 3500 FLH.

[8] Hirth (submitted for publication) expands the model to the Nordic regions, a power system dominated by hydroelectricity.

[9] http://www.ecmwf.int/en/research/climate-reanalysis/era-interim, Berrisford et al. (2009), Dee et al. (2011).

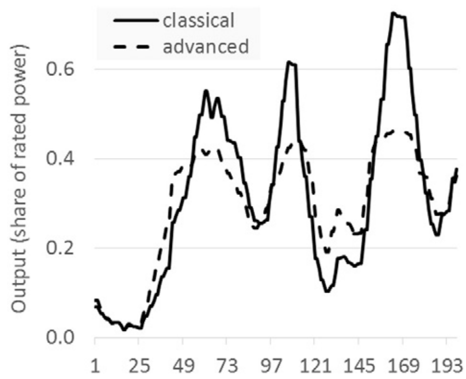


**Fig. 4.** Chronological in-feed during ten days. Annual energy output is the same for both lines, installed capacities differ.

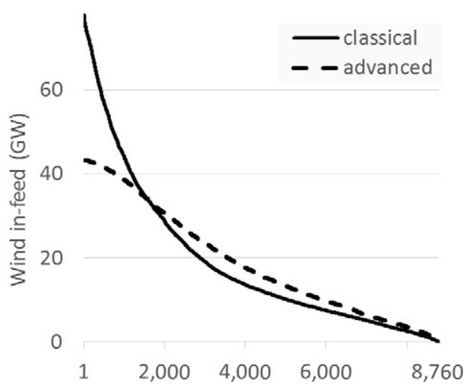


**Fig. 5.** In-feed duration curves (ordered hourly generation) for classical and advanced turbines in Germany, assuming a wind penetration rate of 30%. Annual energy output is the same for both lines, installed capacities differ.

## 4. Model results: the additional market value of advanced wind power

For each level of wind penetration, EMMA was used to calculate the long-term economic equilibrium (or green-field optimum) of the power market. The same wind penetration rate in energy terms was applied in each country. Model-derived hourly electricity prices were then used to calculate the "value factor" of wind power, which we define as the wind-weighted electricity price (wind market value) over the time-weighted electricity price (base price):

$$Wind\ \ value\ \ factor = \frac{Wind\ \ market\ \ value}{Base\ \ price} = \frac{T \cdot \sum_{t=1}^{8760} w_t \cdot p_t}{\sum_{t=1}^{8760} w_t \cdot \sum_{t=1}^{8760} p_t}.$$

For example, a wind value factor of 0.9 means that wind generators receive on average 90% of the base price as revenue per MWh. Hence the value factor is a metric for the valence of electricity with a certain time profile relative to a flat profile (Stephenson, 1973). The wind value factor compares the value of actual wind power with varying winds with its value if winds were invariant (Fripp and Wiser, 2008). We report the average value factor of the Northwestern Europe study region, calculated as the weighted average of the value factor in each country.

**Table 2**
Value factor for observed wind generation and classical profile.

| | Observed | Classical | Difference |
|---|---|---|---|
| 2006 | 0.88 | 0.89 | 1.4% |
| 2007 | 0.88 | 0.88 | 0.3% |
| 2008 | 0.91 | 0.92 | 1.3% |
| 2009 | 0.91 | 0.92 | 0.5% |
| 2010 | 0.94 | 0.95 | 0.5% |
| 2011 | 0.92 | 0.92 | 0.0% |
| 2012 | 0.88 | 0.87 | −0.2% |
| Average | | | 0.5% |

Evaluated with historical spot prices (Germany).

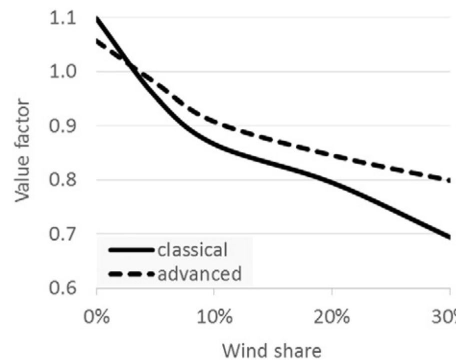


**Fig. 6.** The gap between the black line (classical) and the black dotted line (advanced) represents the impact of advanced turbine technology. The gap is 11 percentage points at 30% penetration.

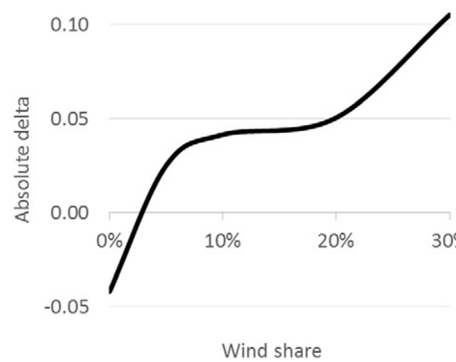


**Fig. 7.** (Absolute) delta. At low penetration, the delta is negative, indicating a *lower* value of advanced turbines. The delta increases with the penetration rate: the more wind power there is in the system, the higher the additional benefit of advanced turbines.

In addition to the main results, robustness tests and sensitivities are applied, and the interaction with other mitigation measures is discussed. At the end of this section, the optimal wind share is calculated, and possible future "more advanced" profiles are evaluated.

### *4.1. Main results*

For classical turbines, the value factor is above unity at low penetration, reflecting the positive seasonal correlation of wind speeds with electricity consumption (both tend to be higher during winter). With increasing deployment, it drops quickly to about 0.7 at a penetration rate of 30%. This reflects earlier findings (Mills and Wiser, 2012; Nicolosi, 2012, among others) and is consistent with observed market data (Hirth, 2013). The value drop is consistent with straightforward economic theory: as the supply of a good increases its relative price declines. The good in question here is "electricity from wind power" (Hirth et al., 2016).

The relative value drops because in those hours during which electricity is supplied by wind power, the price is depressed. The more wind power generated in a given hour, the larger the price drop. With advanced turbines, the value drop is less pronounced because wind generation is distributed more smoothly over time, reducing the price-depressing effect in each individual hour (Fig. 6).

Model results indicate that the difference is large: at 30% penetration, the value factor is 11 percentage points higher ("absolute delta", Fig. 7), corresponding to 15% of the classical turbines' value factor ("relative delta"). In other words, 1 MWh of electricity generated from wind

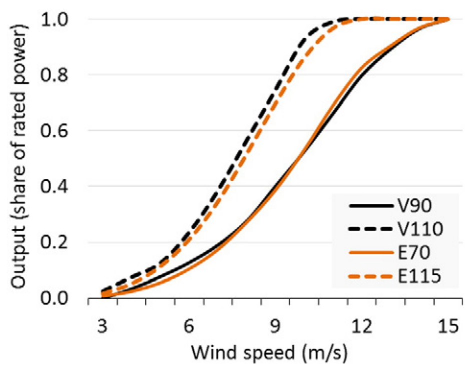


**Fig. 8.** Alternative power curves used for sensitivity analyses.

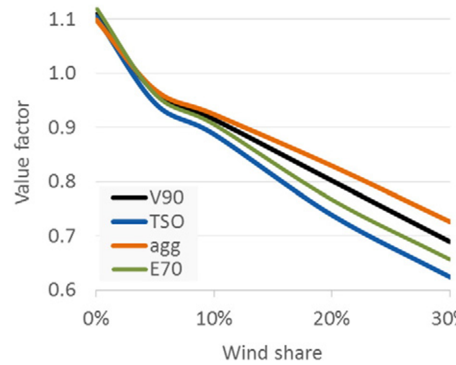


**Fig. 9.** Comparing V90 to alternative classical profiles. All profiles show a similar pattern, two out of three are below V90.

power is 15% more valuable if turbines are advanced. The large size of the delta is the principle finding of this study.

When put in perspective it becomes obvious that the delta is large. It is substantial compared to wind generation costs. If the base price was USD 80/MWh, it would corresponded to USD 9 per MWh, or 11–13% of global average onshore wind levelized electricity costs (LEC).[10] In this case, advanced wind turbines would be able to compete with classical turbines even if their generation costs were 11–13% higher. The delta is also large compared to the value drop: 11 percentage points corresponds approximately to the value drop when changing from 20% to 30% penetration: the market value of advanced wind at 30% is about the same as that of classical wind at 20%. Hence, advanced technology compensates for a 50% increase in wind penetration. Finally, the delta is also large compared to alternative integration options (see 4.4).

At very low penetration, the value of advanced turbines is below that of classical turbines. Wind speeds are higher in the winter season in Europe, when electricity demand is also higher. This positive seasonal correlation benefits wind power, the benefit being larger if generation differences between summer and winter are more pronounced, as is the case for classical turbine design. At higher penetration, the value-depressing effect of wind variability begins to emerge, quickly reducing the value of the more variable classical profile.

At a penetration rate of 20%, the delta is only five percentage points. The energy-value benefit of advanced turbine design only becomes large at high penetration rates, i.e. above 20%. Under current conditions in most power systems, the market value of both technologies is likely to be quite similar.

When comparing 30% advanced wind power to 30% classical wind power, it is not only wind power itself, but the rest of the power system that is somewhat different, as the two model runs are two independent green-field optimizations. Under the given assumptions, total thermal generation and capacity is slightly reduced (2–4%), the residual generation mix is shifted towards base load technologies, $CO_2$ emissions are virtually identical, interconnector capacity are somewhat lower, and the base price is slightly higher (3%). Overall, these differences are relatively small.

### *4.2. Robustness with respect to wind profiles*

To ensure that the estimate of delta is not an artifact of the way in-feed profiles are generated from wind speed data, six additional profiles are tested, three each for classical and advanced profiles. For the "classical" profile we used the following three methodologies:

- A profile derived from a power curve of an alternative wind turbine (Enercon E-70 2.3 MW, specific power rating 581 W/m$^2$), evaluated with ERA-interim wind speeds at 90 m ("E70"). See Fig. 8.
- The observed historical in-feed as reported by the transmission system operators ("TSO"). In countries where TSO data were not available, German data were used.
- An in-feed profile derived from an econometrically estimated aggregated power curve as used by Hirth (2013, 2015b). This power curve was then used to derive in-feed time series for all regions ("agg").

As an alternative "advanced" profile we used:

- A profile derived from a power curve of an alternative wind turbine (Enercon E-115 3.0 MW, specific power rating 285 W/m2), evaluated with ERA-interim wind speeds at 120 m ("E115"). See Fig. 8.
- A scaled profile similar to the one used by Tafarte et al. (2014): the "agg" profile was scaled up to reach an annual average capacity factor of 0.4, but without increasing the maximum value observed in the original data ("scaled").
- As only sites with an average wind speed of 6 m/s were considered, V90 and V110 are based on different locations (wind speed increases with height). An alternative profile was created by using V90 sites only ("V110alt").

Further details on these profiles can be found in Appendix B.

Overall, the results confirm the robustness of our analysis. Two of three alternative classical profiles show an even steeper value drop than that of the V90-based profile we use as a benchmark (Fig. 9). All alternative advanced profiles produce results that are nearly identical to the V110-based profile (Fig. 10). On average, the spread between the advanced and the classical profiles is 14 percentage points at 30%

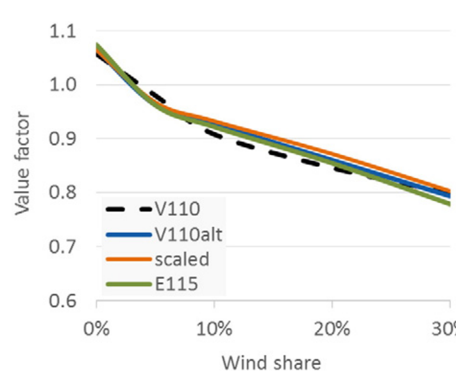


**Fig. 10.** Comparing V110 to alternative advanced profiles. All profiles show a very similar pattern.

[10] Levelized electricity costs are the net present value of the unit-cost of electricity over the lifetime of a generating asset (USD/MWh). They are also called levelized costs of electricity (LCOE) and costs of electricity (COE). IRENA (2015) reports that global mean LEC for onshore wind power was USD 70 per MWh in 2014. IEA (2015a) reports a range of USD 70–80 per MWh for countries having some deployment experience. Moné et al. (2015) report USD 65 per MWh for the United States.

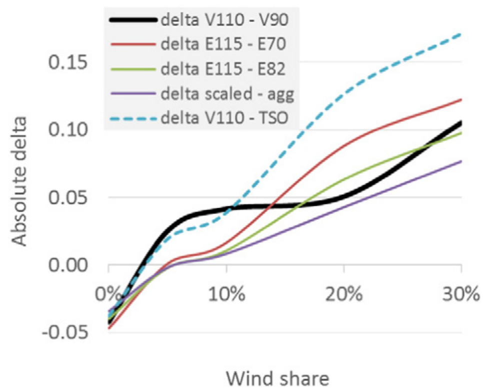


**Fig. 11.** Alternative pairs of profiles to determine the market value delta between classical and advanced turbines.

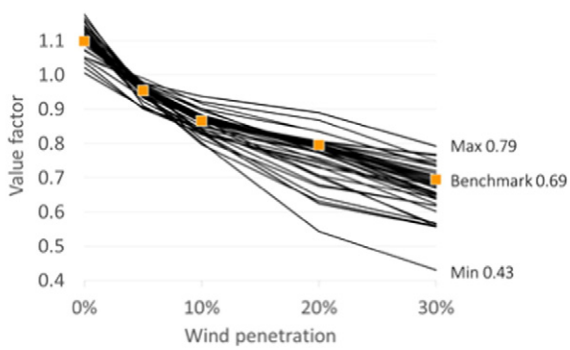


**Fig. 12.** The value factor of classical turbines in all sensitivities. Parameter uncertainty leads to a quite broad range of estimates at high penetration.

penetration, slightly larger than the difference between the V90 and V110 profiles. Fig. 11 displays the delta for alternative pairs of profiles.

The delta in market value between the Enercon E70 and E115 deserves particular attention. Above we compared a classical turbine with a higher nameplate capacity (3 MW) to an advanced machine with a lower capacity (2 MW). Since this study is interested in comparing different specific ratings, this is not an issue per se. However, the turbine market witnesses a trend towards higher capacities. The comparison between the two Enercon models highlights that the result of this study is indeed replicable when comparing a classical machine with a *lower* nameplate capacity with an advanced machine with a *higher* nameplate capacity.

### *4.3. Parameter sensitivities*

To check for robustness with respect to parameter assumptions, a large number of sensitivity runs were performed. Sensitivities included variation of fossil fuel prices, the carbon price, the weather year, thermal plant investment costs, the presence of solar power, interconnector capacity, electricity storage capacity, hydro reservoir parameters, thermal plant flexibility, thermal plant heat rates, must-run constraints for heat and system service provision, maintenance schedules of power plants, seasonality of natural gas prices, capacity payments, investor risk as reflected in the discount rate, spot price caps, and nuclear policy. A complete list of the 70 sensitivities in the sensitivity results can be found in Appendix D.[11]

Many of these assumptions have significant impact on the wind value factor, especially at high penetration rates (Fig. 12). Parameter changes that either make the power system more flexible or the

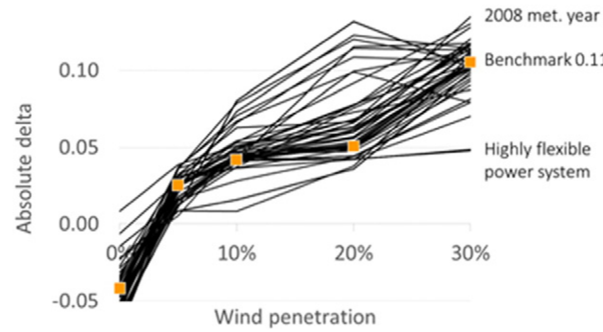


**Fig. 13.** The delta between classical and advanced turbines is remarkably robust: at 30% penetration, 95% of all sensitivities fall between 8.5 and 14.5 percentage points.

merit-order curve flatter tend to increase the value factor at high penetration. This holds for both classical and advanced technology. At 30% penetration of classical turbines, the uncertainty range is 0.43–0.79 around the point estimate of 0.69.

Remarkably, the delta between classical and advanced technology is quite robust; in *all* sensitivities, the delta is positive at wind shares of 5% and higher (Fig. 13). At 30% penetration, the sensitivity range is 5–14 percentage points (or 6–21% of the classical turbines' market value), with a mean and median of 10 and 11 percentage points respectively (15%). In all but two sensitivities, the delta is larger than 7 percentage points (11%). Those two outliers are cases of highly flexible power systems and will be discussed in the following subsection.

Fig. 14 shows the relative delta at 30% penetration for all sensitivities. The estimate of delta is remarkably robust, with 95% of all sensitivity runs resulting in a relative delta between 10% and 20%. The delta is robust to much debated parameters such as the carbon price (only one percentage point variation at a price range of 0–100 €/t), fuel prices (three points variation if coal or gas prices are cut by half or doubled individually or jointly), thermal plant investment costs (one point variation for double investment costs), the presence of solar power (two points variation for solar shares between zero and 10%) and spot market design (one point variation for different levels of price caps and capacity payments).

Two classes of parameters have significant impact on the delta: power system flexibility (see next subsection), and the choice of the weather year (Fig. 15). Testing years between 2008 and 2012 result in deltas between 9 and 14 percentage points at 30% penetration, with a mean of 11 points. While this is a significant variation, it leaves the qualitative conclusions unaffected: in every meteorological year, advanced wind technology is more valuable than classical wind technology.

In many power systems, wind power will not be the only VRE technology that is built on a large scale. Adding solar power has a negative impact on the value factor of wind. However, in the presence of solar PV, the advantage of advanced technology is magnified, i.e. the presence of solar PV increases the delta as defined above (Fig. 16).

These sensitivities indicate that, despite the large uncertainty with respect to many fundamental parameters, it can be expected with high confidence that, at 30% penetration in thermal power systems, electricity generated by advanced turbines is at least 6% and up to 21% more valuable than electricity from classical turbines.[12]

### *4.4. System-friendly renewables versus renewables-friendly system*

Many measures can help integrate VRE into power systems, such as making electricity demand more responsive to available supply, increasing storage capacity, expanding interconnector capacity, or

[11] 70 sensitivities multiplied by 2 wind profiles multiplied by 5 penetration rates results in 700 model runs, each representing a long-term optimum.

[12] These numbers are based on variations of individual parameters. If parameters vary jointly, the delta might be outside this range (for an example, see the "fully flexible power system" in the following subsection).

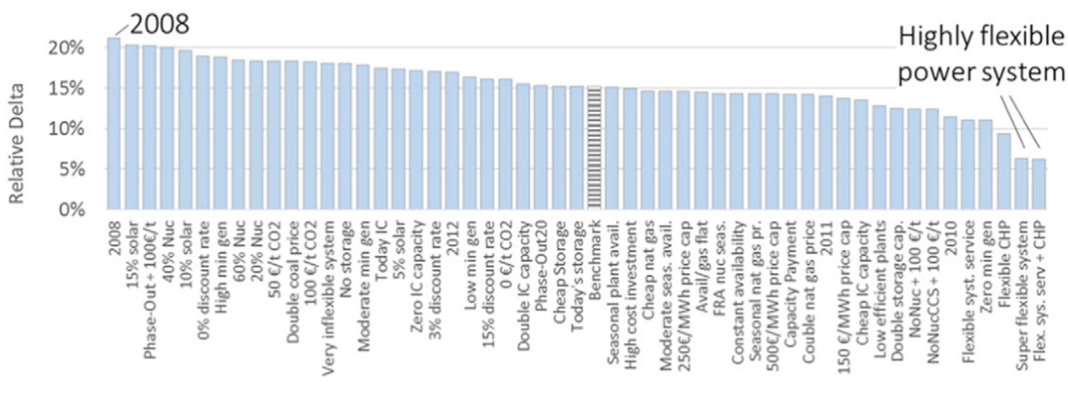


**Fig. 14.** Relative delta at 30% penetration. In 95% of all sensitivity runs, the relative delta is in the range of 10–20%.

upgrading hydropower and thermal plants for increased dispatch flexibility. These integration options tend to increase wind power's market value. For this study, we modeled the following sensitivities: doubling current pumped hydro storage capacity in the study region, doubling current interconnector capacity, fully relaxing the ancillary service constraint that limits thermal plant dispatch flexibility, and fully relaxing the heat constraint that limits the dispatch flexibility of combined heat and power (CHP) plants. These options were implemented individually and jointly.

The impact of advanced turbine design is substantial, not only compared to wind power LEC and to the value drop, but also compared to these alternative integration options (Fig. 17). Doubling storage capacity increases the wind value factor at 30% penetration by less than three percentage points — the impact of advanced wind turbines is five times larger. Doubling interconnector capacity increases the value factor by four percentage points, fully flexible provision of system services by four, and the full flexibility of CHP plants by five points. Advanced wind turbine design increases the value of wind power by more than any of these options.

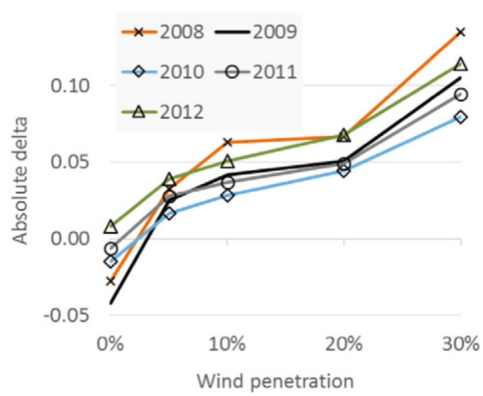


**Fig. 15.** Delta for different weather years.

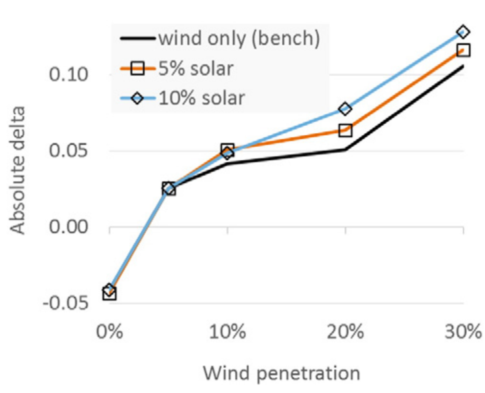


**Fig. 16.** Wind deltas for different solar penetration rates. If solar power is added, the delta increases.

This finding does not infer any direct policy recommendation concerning the relative economic performance of flexibility options, as we do not account for the cost of each option. A cost–benefit analysis of these options would therefore be a promising area for future research.

Advanced wind technology and power system flexibility options can be compared, but they can also be combined. If wind turbine design is advanced and the power system is simultaneously made more flexible, both integration options interact (Fig. 18). According to modeling results, combining all of the above four flexibility measures increases the value factor by 12 percentage points, whereas advanced wind technology increases it by 11 percentage points. However, the joint effect is 17 percentage points, which is less than the sum of individual impacts. In other words, if the power system is already fully flexible,[13] advanced wind turbines increase the wind market value by only 5 percentage points, compared to 11 points if the system is less flexible. If wind power is already advanced, making the power system flexible increases the wind market value by only 6 percentage points, compared to 12 points if wind power design is classical.

We interpret this result as follows: it is the *interaction* of wind power variability and the inflexibility of the power system that causes the value of wind power to decline. The value drop can be mitigated either by making wind turbines more "system-friendly" or by making the power system more "wind-friendly". However, the two mitigation options are not likely to be additive (i.e. the total is less than the sum of the parts); it can be expected that system-friendly wind turbines are a partial substitute for power system flexibility, and vice versa. In others words, the two options are substitutes rather than complements.

This finding has potentially significant policy implications: everything else being equal, system-friendly VRE design tends to be more important for the less flexible power systems. We recommend a follow-up analysis that assesses the additional benefit of advanced turbines in differently flexible power systems.

### *4.5. The value of advanced wind at 30% classical wind*

So far, advanced wind power at a given penetration rate has been compared to classical wind power at the same penetration rate. It is also possible to evaluate the market value of advanced wind power for a given penetration rate of classical turbines. Such an evaluation is

[13] Recall that we model a predominantly thermal power system. A hydro-dominated system is likely to provide more flexibility. See Hirth (submitted for publication) for an assessment.

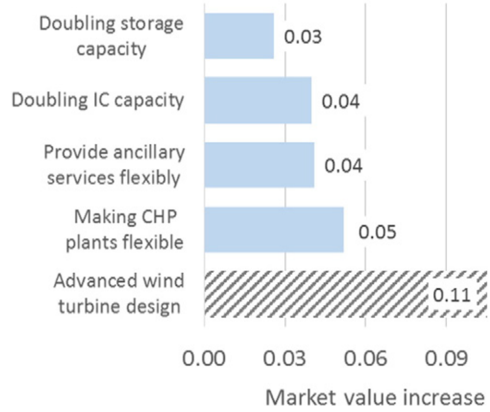


**Fig. 17.** Comparing the impact of individual integration options. The impact of advanced turbine design is substantial in comparison with other integration options.

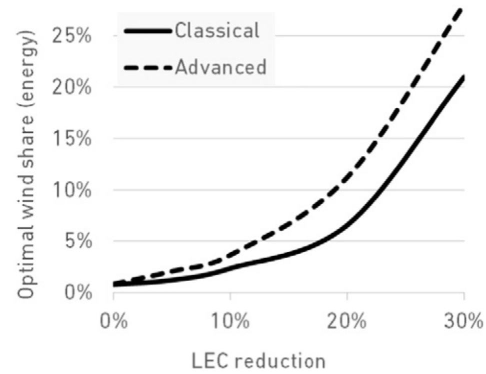


**Fig. 19.** Optimal share of wind power in energy terms as a function of wind LEC reductions relative to today. Classical and advanced wind turbines are assumed to have the same LEC. The model assumption translates to LEC of USD 75 per MWh (0% reduction), which translates to USD 53 at 30% reduction.

relevant for a scenario in which most new turbines are advanced, but most existing turbines are classical.

The value of advanced wind power is somewhat lower for a given penetration rate of classical wind power than the value for the same penetration rate of advanced wind power. This result can be interpreted as advanced turbines being penalized by the price-depressing effect of existing classical turbines. However, for a classical penetration rate of up to 20%, this negative impact remains very small.

### *4.6. Optimal share of wind power*

To illustrate the possible implications of the higher value of advanced wind technology, EMMA was used to estimate the "optimal" (i.e. total system cost-minimal) share of wind power in terms of energy (c.f., Hirth, 2015b). This is the long-term market share of wind power given the phasing out of subsidies and support schemes (i.e., the equilibrium market-driven quantity). For this exercise, it was assumed that classical and advanced turbines have the same LEC. While in some cases this might be a reasonable assumption, in others it is clearly not (see Section 6). Model results should be read as "what if" analyses, not as a forecasts.

Results show that wind deployment is up to 50% higher for advanced than for classical technology (Fig. 19). If wind LEC fell 30% below current cost levels, classical wind power would supply 20% of Northwestern Europe's electricity — if advanced turbines were available at this LEC, they would reach almost 30% of the market share. In other words, the higher value of advanced design has a large effect on the potential market share of wind power.

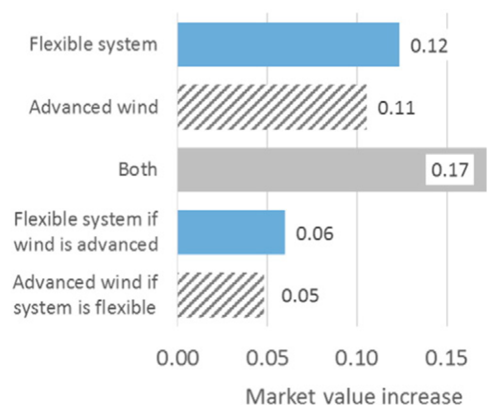


**Fig. 18.** Individual and joint impact of power system flexibility and advanced wind turbines. The joint impact is smaller than the sum of individual impacts, indicating substitutability between advanced wind and power system flexibility.

Model results also indicate that the optimal share of wind power initially increases with the carbon price, peaks at an intermediate level (here around USD 45 per ton), and decreases thereafter (Fig. 20). This surprising non-monotonic shape had been reported by Hirth (2015b), and can also be observed for advanced wind turbines, although at a higher penetration level. The reason for the negative effect of higher $CO_2$ prices on wind deployment lies in investments in competing low-carbon technologies. Nuclear power and carbon capture plants (CCS) are the only non-variable low-carbon technologies in the model (the share of hydro power is fixed), and these two are base load technologies with high investment and relatively low variable costs, i.e. they are economically designed to run around the clock. Baseload capacity increases the slope of the merit-order curve and reduces the market value of VRE and hence its optimal share. However, carbon prices below a certain threshold (here USD 45 per ton) do not trigger any nuclear or CCS investments. Up to this point, carbon pricing simply increases the costs of fossil plants, increasing the electricity price and the market value of VRE. Beyond this threshold, the baseload investment effect dominates the emission cost effect. Of course this finding disappears if nuclear power and CCS are impossible to build due to political or other reasons, and the effect is reduced in size if nuclear capacity is capped. To benefit from stricter climate policy, VRE technologies would need low-carbon mid and peak load generators as counterparts, rather than base load plants.

### *4.7. Advancing further? The value of "super low wind speed" turbines*

Given the substantial impact of advanced technology, one might ask how much more progress is possible. Given the current trend of

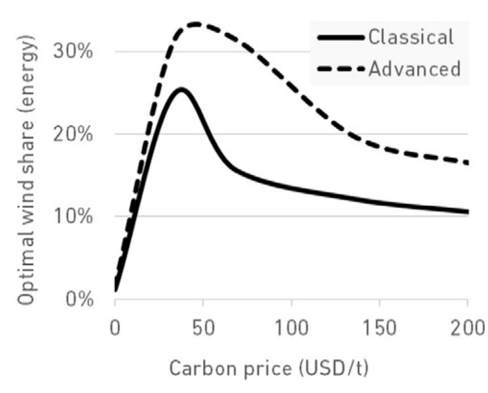


**Fig. 20.** Optimal share of wind power as a function of the $CO_2$ price. Advanced turbines have a 50% higher optimal deployment level (assuming identical LEC).

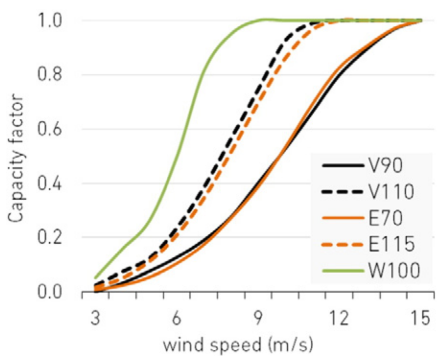


**Fig. 21.** The power curve of a hypothetical "super advanced" turbine with a specific rating of roughly 100 W/m$^2$.

reducing specific power ratings, would even lower ratings increase the market value of wind power further?

Wind turbines with a rating far below 200 W/m$^2$ are currently not commercially available, hence we cannot test the effect of a real-world power curve. For a rough assessment of the effect of very low power densities, a power curve of a hypothetical "super advanced" turbine has been computed by scaling up the advanced power curve by a factor of two (Fig. 21). This corresponds to a specific rating of about 100 W/m$^2$, which is why we labeled the technology "W100". The power curve was evaluated with wind speed data at 120 m height above ground.

The effect on market value is in the expected direction, reducing the value at low penetration and increasing it at high penetration (Fig. 22). However, the additional gain in market value (5 percentage points) is smaller than the difference between advanced and classical design (11 percentage points). This reflects diminishing returns. However, additional benefits from reduced balancing and grid costs can be expected.

## 5. Further benefits: reduced forecast errors and grid costs

The principal contribution of this study is to assess the impact of advanced plant design on bulk power value. This section briefly reviews further benefits: reduced forecast errors, reduced grid costs, and provision of system services. Overall, these additional benefits seem to be positive and significant, but smaller than the gain in bulk power value.

### 5.1. Reduced forecast errors

The impact of advanced turbine design on forecast errors is not clear a priori: on the one hand, less wind capacity is installed (reducing the aggregated forecast error), while on the other hand, the power curve is steeper (increasing individual forecast errors).

Forecast errors were evaluated by assessing the one-hour persistence forecast, which is the hour-to-hour change in wind power

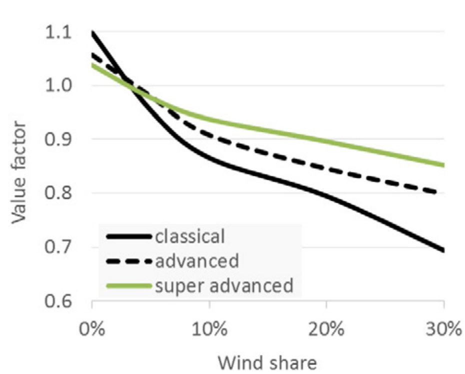


**Fig. 22.** The market value of a "super advanced" turbine with a specific power rating of 100 W/m$^2$ is not much higher than that of advanced design.

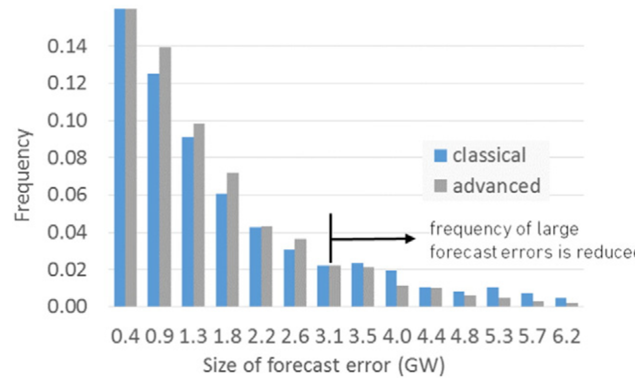


**Fig. 23.** Distribution of one-hour persistence forecast errors (at 30% wind penetration, corresponding to 90 GW classical wind capacity). With advanced turbines, large forecast errors (above 3.1 GW) occur less frequently.

generation. Such short-term forecast errors are relevant for balancing services and can be quite costly if they increase the need to hold balancing reserves (Hirth and Ziegenhagen, 2015).

Take the example of 30% wind penetration (Fig. 23). It is apparent that with advanced turbines, small forecast errors (below 3.1 GW) are more frequent, but large errors are less frequent. With classical turbines, in 6% of all hours the persistence forecast error is above 5 GW (compared to an installed capacity of 90 GW). With advanced turbines, the 5 GW mark is exceeded in less than 2% of all hours.[14] This is important for economics and system operation, since it is *large* forecast errors that determine the size of the balancing reserve requirement. This suggests that advanced wind turbines have the additional benefit of reducing balancing costs.

This analysis has a number of caveats and should be understood as a first and rough assessment. Further analysis is needed to account for longer time horizons, weather prediction tool-based forecasting, correlation of wind forecast errors with other sources of system imbalances, and should assess not only the physical size of forecast errors, but also the actual costs of balancing. Further research in this area is relevant and promising.

### 5.2. Reduced grid costs

The design of wind turbines potentially also affects grid costs, both (shallow) grid connection and (deep) grid expansion and reinforcement costs. We discuss both types of grid costs in turn.

*Grid connection costs* are very project-specific. In general, the cost of connecting wind farms to the transmission grid is a function of capacity installed, not energy generated. Economies of scale in grid investments imply that costs are likely to be non-linear in capacity. Nevertheless, most published studies assume that connection costs are proportional to installed capacity. Most estimates are in the range of USD 80–170 per kW (Table 3).

*Grid expansion costs* are even harder to assess in a general manner, because they are often calculated in long-term scenarios where the drivers for grid expansion are numerous. Nevertheless, a few studies have linked grid expansion costs to wind capacity. Holttinen et al. (2011) estimate costs to be USD 60–300 per kW, based on an extensive literature review.

Both grid connection and expansion costs are reported "per kW". They translate into costs "per MWh" via the annual average capacity factor. As modeled in this study, advanced wind turbines have a capacity

[14] Due to the lower installed capacity in the advanced case, 5 GW corresponds to a larger forecast error when measured against installed capacity. However, for system operations and the need for holding reserves, the absolute forecast error is the relevant metric, i.e. the comparison is not about forecast quality but about size of forecast errors.

**Table 3**
Grid connection costs for onshore wind power.

| Source | Cost estimate | Region |
|---|---|---|
| Krohn et al. (2009) | EUR 109/kW | Europe |
| Swider et al. (2008) | EUR 45–170/kW | Germany |
| Blanco (2009) | EUR 150/kW | Europe |
| WindGuard (2013) | EUR 73/kW | Germany |
| Frontier Economics (2013) | GBP 80/kW | UK |
| Tegen et al. (2013) | USD 148/kW[a] | US |
| IRENA (2012) | 11–14% of total capital costs | Global |

[a] Including substation and internal grid of the wind park.

**Table 4**
Reduced grid costs with advanced turbine design.

| | Per capacity (USD per kW) | Per energy (USD per MWh) | | |
|---|---|---|---|---|
| | | Classical design | Advanced design | Savings |
| Grid connection | 80–170 | 2.8–6.0 | 1.5–3.2 | |
| Grid expansion | 60–300 | 2.1–10.6 | 1.1–5.7 | |
| Total | 140–470 | 4.9–16.6 | 2.7–8.9 | 2.3–7.7 |

Numbers may not total due to rounding.

factor nearly twice that of classical turbines. Hence, for a given penetration rate, installed capacity would be about 45% reduced compared to classical technology. Consequently, grid costs are reduced by 45%. For classical turbine design, the sum of grid connection and expansion costs is USD 5–16 per MWh.[15] Advanced turbine design would reduce grid costs by USD 2–8 per MWh (Table 4).

These benefits are substantial, not only in absolute terms but also compared to the gain in bulk power value. Compared to the gain of 13 percentage points in value factor, the savings of grid costs are about 1/4 to 3/4.

### *5.3. System services provision: improved system operation*

Modern wind turbines are able to provide system, or ancillary, services such as balancing power, (synthetic) inertia, voltage support, and fault-ride-through capability. While system operation might benefit from wind turbines offering such services, supply is often not recompensed. Moreover, the ability to provide such services is not necessarily linked to "advanced" design as defined above (low specific rating, high tower).

Balancing services are an exception: the provision of balancing power is paid for in many markets. With higher capacity factors, advanced wind turbines are likely to be able to provide more "firm" capacity that can be used as downward balancing reserve. They can also supply balancing power during more hours of the year. The economic benefit of doing so, however, is highly market-specific and not quantified here.

## 6. The cost of advanced wind power

So far, we have discussed the *benefits* of advanced wind turbine design. However, the gain can come at a cost: in terms of generation costs (LEC), low wind-speed turbines are sometimes, but not always, more expensive than classical designs. This section is based on published studies and interviews with manufacturers. It is not more than a first step; further research is warranted.

Molly (2011, 2012, 2014), Lantz et al. (2012), de Vries (2013), Gipe (2013), Tafarte et al. (2014), Wiser and Bolinger (2015), and Fraunhofer IWES (2013) provide valuable background on engineering, technology, and history of low-wind speed turbines. However, the published literature does not provide cost figures for classical versus advanced turbines, and manufacturers do not regularly publish price data. Bloomberg New Energy Finance, a consulting company that publishes a wind turbine price index, distinguishes "old" and "new" models.[16] The index, which reports investment cost rather than LEC, showed a 23% price gap in 2014 (IRENA, 2015, p. 19).

In the 1980s, manufacturers offered turbines with specific power ratings of as much as 1000 W per square meter of area swept by the rotor. Today, low wind speed turbines are rated at 200 $W/m^2$ — at intermediate wind speeds; they generate five times more electricity for each kW than their older peers. The long-lasting trend towards lower specific ratings has accelerated in recent years: in the United States, average specific ratings of new turbines dropped from 400 $W/m^2$ in 1998/99 to 250 $W/m^2$ in 2014 (Wiser and Bolinger, 2015). Turbines with power ratings typical for low wind speeds are also now regularly employed at higher wind speed sites.[17] A similar trend can be observed for offshore turbines in Germany, where specific ratings of new turbines have dropped from ~500 $W/m^2$ below 350 $W/m^2$ (Fraunhofer IWES, 2013).

At penetration levels currently observed in most countries,[18] the electricity generated from low wind-speed turbines is not significantly more valuable than the electricity from classical turbine design. Moreover, in many countries, support schemes such as feed-in-tariffs are impermeable for price signals. As such, it is reasonable to assume that manufacturers have not optimized the value of electricity generated, but simply minimized generation costs. Hence, the recent trend to deploy "advanced" turbine design in certain locations is likely not to be associated with higher LEC, but apparently represents the cost minimum for the investor. May's (2015) evidence supports this argument. It seems that technological progress is shifting the cost-minimum towards higher annual average capacity factors.[19]

At high wind speed sites, the situation is different — as evidenced by the higher specific ratings commercially deployed at these sites. In these conditions, minimizing LEC results in "classical" turbine design. Switching to "advanced" design can thus be expected to entail additional plant level costs per unit of energy produced. Since mechanical loads on the wind turbine generator result primarily from the swept area, deploying lower specific ratings at high-wind speed sites can be seen as simply reducing generator size. The degree to which generator costs are high or low compared to other turbine component costs will thus determine how high the LEC cost penalty will be. If increasing generator size is less costly, deploying low specific ratings will be less attractive and vice versa.

Whether these additional costs are compensated for by the ability to produce higher-value electricity can be determined by cost-benefit analysis. If policy and market design transmits price signals to investors, advanced design can be expected to become more relevant for high wind speed sites.

[15] Assuming 40 years life time and a 6% discount rate. For shorter life-time and/or higher discount rates, costs (and savings) would be higher.

[16] "'Old models' are those designed for the highest wind conditions. 'New models' typically have longer blades and are designed for lower-speed conditions." (IRENA 2015, p. 19).

[17] "Turbines originally designed for lower wind speeds are now regularly employed in both lower and higher wind speed sites [...] Low specific power and IEC Class 3 and 2/3 turbines are now regularly employed in all regions of the United States, and in both lower and higher wind speed sites. In parts of the interior region, in particular, relatively low wind turbulence has allowed turbines designed for lower wind speeds to be deployed across a wide range of site-specific resource conditions." (Wiser and Bolinger, 2015, p. vii).

[18] Denmark, Ireland, Portugal and Spain are among the notable exceptions.

[19] In individual markets, other drivers might have contributed the development of low wind-speed turbines. If land is scarce and support schemes are generous (as in the UK or in Germany), it might be rational to maximize yearly output for a given site, not minimizing LEC. Similarly, if deviations from yearly generation levels are penalized by the support scheme (as in Brazil), it might be beneficial to increase capacity factors, because this reduces inter-year variations. However, given the lack of evidence on the matter, it seems unlikely that investors will build advanced turbines in anticipation of the value increase discussed in this study.

## 7. Conclusions, policy implications and further research

The design of wind turbines has a significant impact on the system and market value of the electricity they produce. "Advanced" turbine technology, using taller towers and a larger area swept per rated capacity, generates higher annual average capacity factors and smoother output, which boosts the long-term market value of wind power at high penetrations. We find a 15% bulk power value increase at 30% penetration. That means that each megawatt-hour is sold at a price on wholesale markets which is 15% higher than that from a classical turbine. Other means to secure the value of wind power, such as increasing storage or interconnector capacity, have less of an impact. With advanced wind technology, the value at 30% penetration is at the same level that is reached by classical technology at 20% penetration.

Additional benefits are likely arise from reduced balancing and grid costs as well as system service provision. While this estimate is subject to uncertainty, the increase in value is quite robust across a large set of different parameter settings (fossil fuel and carbon price, weather year, thermal plant investment costs, interconnector capacity, electricity storage capacity, thermal plant flexibility etc.).

The technological innovations that have allowed developers to tap into low wind-speed sites have not only contributed to reducing plant level costs at these sites; they have also increased the possible long-term value of wind power to power systems.

Further refinement of the analysis is warranted, including a more detailed assessment of the benefits of advanced turbine design for balancing markets; of advanced wind power in systems with significant amounts of hydroelectricity; of a mix of different advanced and classical turbine types; and of costs and cost drivers, potentially including learning curve estimates of individual turbine parts.

Notwithstanding this, the findings of this study allow us to draw seven main conclusions. The first of these conclusions refers to previous studies, including our own work:

1. Under business-as-usual assumptions, wind power is likely to be more competitive than earlier studies have suggested, to the extent that these studies relied on observed wind profiles.

Four conclusions have implications for the design of renewable energy support mechanisms:

2. Well-designed electricity markets reflect the varying value of electricity across time and location. In order to further stimulate technological development, policies should pass through these price signals to wind investors. Feed-in premium models or capacity-based support are possible steps in this direction.
3. Onshore wind power is a remarkably heterogeneous group of technologies that produce electricity of different system value. As such, policy mechanisms that seek to minimize generation costs alone may fail to minimize support costs. This is also true for competitive bidding processes such as auctions.
4. The benefits of advanced wind power occur at different parts of power systems and markets. Policy and market design should seek to factor in system-wide benefits in the prices that drive investment decisions in wind power. This could be achieved by implementing more cost-reflective grid fees and imbalance pricing mechanisms, and by allowing wind power to participate in system service markets.
5. The increased value of advanced wind turbines depends on the penetration level of wind power. At low penetration rates, the most economic choice is classical wind turbine design. However, above a certain penetration threshold, this is no longer the case. This underlines the need to provide investors with clear visibility on the long-term deployment trajectory and appropriately designed support policies in order to make the right investment choices during rapid scale-up of wind power and avoid lock-in.

We close with two recommendations for future research:

6. Scaling existing wind power production time series data from historical production data – even if this is based on a large fleet of generators that cover a large geographic footprint – can potentially compromise the analytical robustness of findings related to the competitiveness of wind power at high penetration rates. Studies relying on the scaling of historical time series are thus likely to systematically overstate some of the challenges associated with reaching high shares of wind power. For high wind scenarios, historical data should not be used without caution.
7. More generally, the dynamic technological advancements of wind power technology highlight the critical role of unanticipated innovation in long term economic analysis and the inherent difficulty of accurately capturing such technological progress ex-ante. Extrapolating existing technology parameters into the long-term future might underestimate the possibility of adapting to a changing environment. Modeling changing energy systems based on current technology is likely to overstate the rigidity of the status quo.

## Appendix A. Supplementary material

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2016.02.016.

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