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Impacts of Wind Turbine Technology on the System Value of Wind in Europe

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Ea Energy Analyses

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List of Acronyms

BaU	business as usual
CAPEX	capital expenditures
CF	capacity factor
CfD	contract for differences
ETS	emission trading scheme
FLH	full load hours
HH	hub height
IEA	International Energy Agency
LCOE	levelized cost of electricity
LWST	low wind speed turbines
MV	market value
NTC	net transfer capacity
OEM	original equipment manufacturer
PV	photovoltaics
RES	renewable energy sources
SP	specific power
TSO	transmission system operator
VF	value factor
VRES	variable renewable energy sources
WEO	World Energy Outlook

Executive Summary

Power systems around the world are undergoing dramatic changes, driven by technological development, increasing competitiveness of renewable energy technologies, and the political agenda to mitigate climate change and reduce the dependency on fossil fuels.

In Europe, renewable energy deployment is determined through targets set by the European Union as well as national goals, which are often more ambitious. Projections in this report estimate that the European power system's[1] total renewable energy share will double from today's values to more than 60% by 2030. Forty percent of all power generation will be based on variable sources from wind and solar power, with land-based wind being the single most important source, accounting for around 17% of all generation by 2030. As power systems are transformed, renewable energy integration will become increasingly important. Integration measures include a wide range of options, from operational procedures to flexible generation resources, flexible demand, and system-friendly deployment of variable renewable generation.

This report analyzes the impact of different land-based wind turbine designs on grid integration and related system value and cost. This topic has been studied in a number of previous publications, showing the potential benefits of wind turbine technologies that feature higher capacity factors. Building on the existing literature, this study aims to quantify the effects of different land-based wind turbine designs in the context of a projection of the European power system to 2030. This study contributes with insights on the quantitative effects in a likely European market setup, taking into account the effect of existing infrastructure on both existing conventional and renewable generation capacities. Furthermore, the market effects are put into perspective by comparing cost estimates for deploying different types of turbine design. Although the study focuses on Europe, similar considerations and results can be applied to other power systems with high wind penetration.

This report studies three different scenarios for the future deployment of land-based wind turbines, with increasing hub heights and decreasing specific power (SP) ratings.[2] Both parameters lead to higher capacity factors, thereby changing generation patterns and reducing the need for installed wind power capacity at equal wind power shares. However, both measures imply higher cost per megawatt (MW) of installed capacity. The three scenarios are:

- **BaU** – Business as usual, where all new installations of land-based wind turbines from today to 2030 are assumed to have a specific power rating of 325 W/m^2 and a hub height of 100 m. These values correspond to the average new installations of land-based wind turbines in Europe in recent years.
- **Likely –** Considers specific power of 250 W/m^2 and a 125-m hub height, a turbine technology that is likely to characterize the European situation in 2030. The projection of

[1] Countries included: Austria, Belgium, Czech Republic, Denmark, Estonia, France, Finland, Germany, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Sweden, Switzerland, UK (excluding Northern Ireland).
[2] Specific power (SP) is the ratio between the capacity rating and the rotor area. At equal capacity rating, lower specific power is achieved by increasing the diameter of the rotor.

the characteristics is based on the expert elicitation survey conducted within the framework of IEA Wind TCP Task 26 [1].

- **Ambitious –** Represents a very aggressive development in terms of both specific power and hub height across the entire continent, with values of 175 W/m^2 and 150 m, respectively.

The Balmorel model, an open-source model for analyzing the combined power and heat sector in internationally integrated markets, has been used to simulate the power system development and optimal dispatch to 2030. The modeling is done in two steps: the first step is an optimization of investments in new generation capacity and decommissioning of unprofitable plants, and the second step is a detailed hourly operation optimization considering unit commitment.

The penetration of wind and solar power in terms of energy volume is kept constant across the three scenarios, while the remaining system is optimized in terms of both investment and dispatch.

Wind Turbines with Taller Towers and Larger Rotors Have Higher Market Value

The projection of the European power system shows increasing power price levels compared to 2015-2017, driven by higher fuel and CO_2 prices and decommissioning of conventional power plants (German prices are shown in Figure ES1). These projections are inherently uncertain and affected by assumptions about the development of fuel and CO_2 prices, technology cost, electricity demand, and future power market designs.

On average, wind power achieves lower prices in the wholesale market compared to the average market price. In 2015, this difference was around 15% in Germany and Denmark, meaning the value factor of land-based wind power was around 85%. Toward 2030, the value factor falls to around 79% in Germany in the BaU scenario. This is an indication of increasing system integration costs.

On the other hand, when deploying turbines with higher hub heights and lower specific power ratings, the value factor of wind power in 2030 increases to 85% and 90% in the Likely and Ambitious scenarios, respectively. By 2030, the market value (MV) of wind power in the wholesale market can be as much as 4.3 €/MWh higher when employing high-capacity-factor turbines relative to the lower capacity factor turbines assumed in the BaU scenario. To determine if wind turbines with high capacity factors are more economically feasible, the higher market value should be held up against possibly higher generation costs related to the change in turbine design.

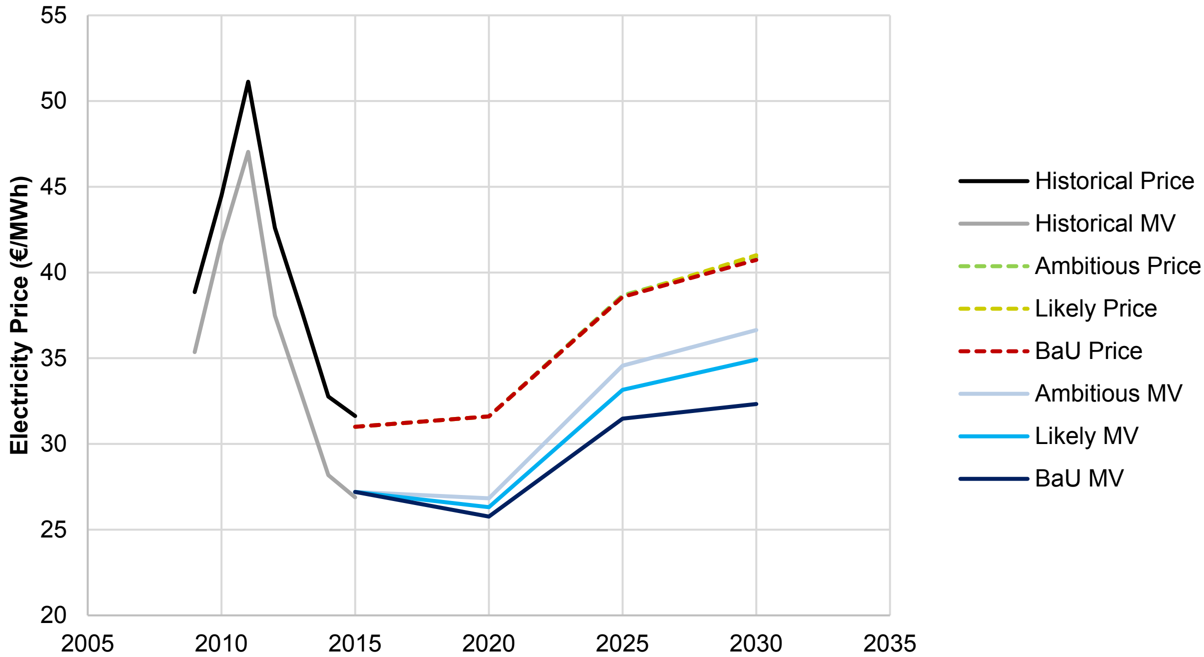


Figure ES1. Projection of average prices and market value (MV) of wind in Germany toward 2030

Trade-Offs between Cost and Value are Required to Assess Optimal Turbine Choice

Wind turbines with taller towers and larger rotors have higher specific cost (investment and maintenance cost in €/MW). At the same time, higher capacity factors have a downward effect on the levelized cost of energy (LCOE). Therefore, the total benefit of choosing specific turbine types depends on the sum of profile cost savings (increased market value) and differences in LCOE from a pure technology perspective. Effects of technology choices on capacity factors depend on the available resource; therefore, optimal turbine choice will vary by region. The main focus of the current study is on modeling and evaluating the system effects (value of wind power). However, for comparison, impacts of turbine design on LCOE have been estimated, in part based on extrapolation of available data, because the projected turbine design is not deployed widely today. This is especially true in the Ambitious scenario.

For northwestern Germany, system simulations estimated a profile cost savings of around 4.6 €/MWh in the Ambitious scenario by 2030 compared to BaU. For additional comparison, the estimated technology cost in this study shows that the LCOE of Ambitious turbines is only increased by 1.3 €/MWh when placed in northwestern Germany, leaving a net benefit of approximately 3.3 €/MWh (Figure ES2). In regions like southern Germany, the LCOE is lower for the Ambitious turbines because capacity factors improve to a greater extent on low-wind sites. Conversely, in regions with strong wind resources (illustrated by western Denmark in Figure ES2), the additional cost of Ambitious turbines offsets the profile cost savings, leading to a net additional cost compared to BaU. In reality, optimal wind turbine designs will vary widely across Europe depending on site conditions.

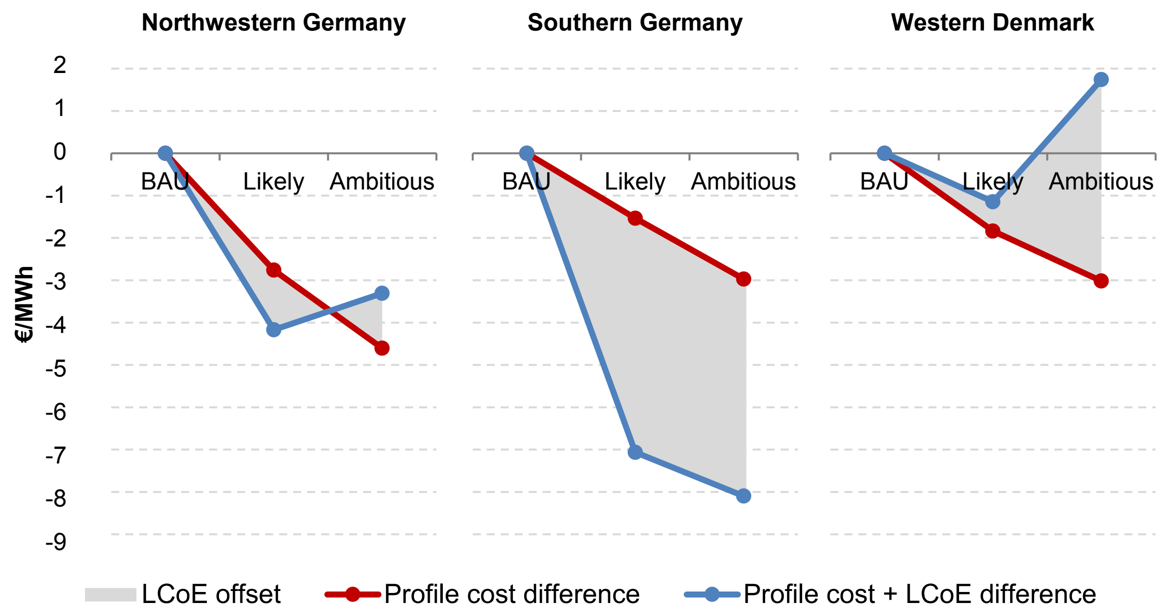


Figure ES2. Differences in profile cost and estimated LCOE for BaU, Likely, and Ambitious turbines in three different regions. All values shown for 2030.

The Overall System Perspective

Potential savings from an overall system perspective arise from both the changing costs of land-based wind deployment, as well as from savings from the adjusted generation and investment patterns in the remaining system compared to the BaU scenario (Table ES1). The latter savings from the remaining system are mainly related to fuel savings due to a lower need for medium- and peak-load operation and, to a lesser extent, reduced needs for conventional generation capacity.

With regard to the remaining system, both the Likely and Ambitious scenarios show savings of around 280 million €/year by 2030.

In the Likely scenario, the LCOE of new land-based wind decreases on average across regions, providing an overall system savings and considering wind energy costs and the remaining system, of around 870 million €/year in 2030. This corresponds to around 0.6% of the total system cost.[3] Alternatively, the LCOE for turbines in the Ambitious scenario increases on average across regions. The total additional spending in the Ambitious scenario—again, considering wind energy costs and the remaining system—is up to 450 million €/year by 2030. Figure 2 shows Ambitious turbines can be the optimal choice in many regions. If deployed everywhere, however, the total scenario cost will increase compared to BaU.

Estimating the additional investment cost for advanced turbines is subject to uncertainty. Both the Likely and Ambitious turbines will have higher investment cost per megawatt due to the larger rotors and higher towers. If these additional costs, which are estimated to be around 28% and 82%,

[3] Total system cost: all fuel, operation and maintenance, and emissions costs as well as capital cost for all units deployed after 2015.

respectively, prove to be lower, the scenario economy will improve, and the Ambitious scenario could potentially show better economics than BaU.

Further system savings in the Likely and Ambitious scenarios could occur from enabling higher penetration of wind or solar power, but these options have not been analyzed in the current study. Additionally, optimization of turbine choices for individual regions, depending on the wind resource quality, would result in lower costs than any of the scenarios shown here.

Table ES1. Distribution of Cost Differences Compared to BaU on New Turbine Installation and Remaining System

		Cost Differences Remaining System (M€/year)	**Cost Differences Wind Turbines** (M€/year)	**Total Cost Differences** (M€/year)	**Total Cost Differences** (€/MWh new wind)
Likely	2020	-20	-180	-200	-2.2
	2025	-90	-395	-485	-2.1
	2030	-275	-590	-865	-2.3
Ambitious	2020	-10	115	105	1.2
	2025	-110	410	305	1.3
	2030	-285	730	450	1.2

Note: Costs per megawatt-hour are calculated as the total cost relative to generation from all new wind turbines installed after 2015.

Future Renewable Energy Policy Schemes Should Consider Value Differences

The analyses in this report show the importance of technology design considerations when evaluating the value of wind power generation and illustrate the need to include both cost and value perspectives. This is relevant for wind power developers and turbine manufacturers, as well as for policymakers designing renewable energy support schemes. Failing to take into account the technological development in land-based wind power when analyzing the development of power systems could result in an underestimation of the competitiveness of wind power and its potential contribution to a cost-effective system development. It is therefore recommended that future wind power policies take into account options for advanced turbine design.

It is also important to recognize that wind power support schemes could impact market signals such that wind developers may not make optimal technology choices. An example is a fixed feed-in tariff that remunerates generation from different types of wind turbine technologies with the exact same amount per megawatt-hour.

As wind penetration grows, it becomes increasingly important to design policy measures to more accurately reflect the real value differences among different wind technology options. Other considerations on support scheme design, such as market risks and the effect on developers' cost of capital as a result of risk assesment, have not been analyzed.

Table of Contents

Acknowledgments iii
List of Acronyms iv
Executive Summary v
List of Figures 1
List of Tables 3
1 Introduction 4
1.1 Research Motivation 4
1.2 Contribution to Existing Literature 5
1.3 Trends in the Technology 6
1.4 The Market Value of Wind 10
2 Wind Turbine Technology Scenarios 13
2.1 Analysis Focus and Scenarios Setup 13
2.2 Sensitivity Analyses 14
3 Methodology 15
3.1 The Balmorel Model 15
3.2 Simulation Setup 17
3.3 Modeling of Wind Power Generation 18
4 Model Input Data and Assumptions 31
4.1 Existing System: Generation and Transmission 32
4.2 Fuel and CO_2 Prices 32
4.3 Technology Cost 34
4.4 RE in Europe 38
4.5 Transmission System Expansion 39
4.6 Investment Setup 40
5 Limitations of the Analysis 42
5.1 Market Setup in Germany 42
5.2 Uncertainty in Wind Penetration Projections 42
5.3 Turbine Cost 42
5.4 Dispatch Model Limitations 43
5.5 Wind Modeling 43
6 Results 45
6.1 System Results in the BaU Scenario 45
6.2 The Effect of Technology Advancement on the System 49
6.3 Total System Cost 59
6.4 The Effect of Technology on the Market Value of Wind 62
6.5 Levelized Cost of Energy and Site Perspective 70
6.6 Sensitivities on Turbine Design 72
7 Discussion and Conclusion 75
7.1 European Power System 75
7.2 Value of Wind 75
7.3 Cost and Benefit Perspective 77
7.4 Lower Specific Power vs. Higher Hub Heights 79
7.5 Implications for Policy 79
8 Recommendations for Future Research 82
Glossary 84
References 86
Appendix 1 89
Appendix 2 91

List of Figures

Figure ES1. Projection of average prices and market value (MV) of wind in Germany toward 2030vii
Figure ES2. Differences in profile cost and estimated LCOE for BaU, Likely, and Ambitious turbines in three different regions. All values shown for 2030. viii
Figure 1. Historical development of specific power (left) and hub height (right) in the United States, Germany, and Denmark. Data for 2017 refer to the sample size available to date. Source: [10], [11], [12] 7
Figure 2. Specific power of newly installed turbines in Germany by wind zone. Wind zone I (weak wind locations), wind zone II (typical inland locations), wind zone III (near-coast locations), and wind zone IV (coastline). Source: [11] 8
Figure 3. Illustration of the effect of reduced specific power (left) and increased hub height (right) 10
Figure 4. Development of price and market values of wind and large thermal plants (above) and value factor development in Denmark with respect to the wind penetration (below). 2017 data are based on data for January till September. Source: [16] 11
Figure 5. Value drop at increasing wind market share for Germany, Denmark, and Sweden, based on actual market data. Source: [17] 12
Figure 6. Scenario setup for the analysis 14
Figure 7. Setup of sensitivity analyses 14
Figure 8. The Balmorel Model characteristics: infographic regarding data, model, solver, and results 16
Figure 9. Geographic scope of the model and of the current analysis 17
Figure 10. Simulation setup in terms of common framework and specific scenario runs 18
Figure 11. Principal wind power modeling in Balmorel. Aggregated power curves are defined for the existing wind power generation fleet and future wind power vintages separately 20
Figure 12. Average wind speed map and land-based locations selected for each Balmorel region23
Figure 13. Offshore wind locations represented in the model (northern Europe) 24
Figure 14. Modeling of wind-to-power module, historical, and future technology. Index *T* represents the different technologies, while *A* represents the wind areas. 26
Figure 15. Power curves selected for the three main scenarios 27
Figure 16. Smoothing procedure example—from reference to smoothed power curve 28
Figure 17. Example of metered wind farm output compared to theoretical power curve. Source: [25] 29
Figure 18. Full load hours comparison between BaU and Ambitious scenarios 30
Figure 19. Fuel price projections assumed in the simulations 33
Figure 20. Technology cost of VRES. New projections based on latest tender results compared to technology catalogue (tech-cat). 34
Figure 21. Estimated investment cost as function of diameter. Illustration based on data from [31] and own calculations. Applied exchange rate USD to EUR equal to average 2015 rate of 0.90. Diameters for turbine design applied in scenarios correspond to 2020 values. 36
Figure 22. Estimated investment cost as function of hub height. Illustration based on data from [35] and own calculations. 37
Figure 23. Specific investment cost for land-based wind turbines in 2030, dependent on hub height and specific power. Blue lines show cost development if only specific power is changed, red lines show development if only hub height is changed, and green lines show development of investment cost if both hub height and specific power are changed, corresponding to the Likely and Ambitious scenarios. See Section 6.3 for details on calculation of "threshold values". Source: Own calculations based on [30], [31], and [35]. 38
Figure 24. Transmission capacity between regions in 2016 (left) and additional expansion in the period 2016-2030 (right) based on TYNDP16 40
Figure 25. Subdivision of Germany in regions in the model (left) and main transmission bottlenecks in the German grid (right) 39
Figure 26. Evolution of annual generation in the modeled region (Europe) 45
Figure 27. Evolution of annual electricity generation in Germany 46
Figure 28. Average wholesale electricity market price by region in the BaU scenario in 2030 48

Figure 29. Land-based wind duration curve for Germany across the three scenarios in 2020 (top), 2025 (middle), and 2030 (bottom) 50
Figure 30. Monthly distribution of wind generation in Germany (2030) for the Ambitious and BaU (left axis) scenarios. The dotted line is the ratio between the two (right axis). 51
Figure 31. Seasonal variation of the combined wind and solar profile for the Ambitious and BaU scenarios, Germany 2030. Monthly solar and wind for the Ambitious scenario are shown as reference 51
Figure 32. Load duration curve and residual load duration curve by scenario, Germany 2030 52
Figure 33. Capacity credit of land-based wind [CCw] (left axis) and reduction of the peak (right axis) 53
Figure 34. Curtailment levels of land-based and offshore wind by scenario and year in Germany 54
Figure 35. Dispatch in two selected weeks for the region DE-ME in 2030 (top) and export to neighboring regions (bottom) 55
Figure 36. Variation of generation across scenarios in the modeled region, compared to the BaU scenario 56
Figure 37. Development of German average wholesale electricity prices (consumption weighted across regions) resulting from the model 57
Figure 38. Price duration curve for the DE-NW region in 2030, showing the reduction of the merit-order effect in the market 58
Figure 39. Differences in total system cost compared to the BaU scenario. Capital cost is calculated using a lifetime of 20 years and a real discount rate of 4%. 60
Figure 40. Market value of wind (MV) in Germany by scenario, compared to the average electricity price 62
Figure 41. Explanation of the higher value for advanced designs. Total production in TWh (right axis) for each of the five bins of the price duration curve (left axis). The arrows indicate the change in generation from the BaU to the Ambitious scenario. Germany DE-NW, 2030. 63
Figure 42. Value factors for land-based wind in Germany for the three scenarios. Between 2020 and 2025, the effect of increased interconnection in the North-South axis is reflected in higher VF. 64
Figure 43. Value factor for conventional generators grouped in baseload (nuclear, lignite, coal) and peakers (natural gas and oil) 65
Figure 44. Price duration curve comparison between historical realized prices in Germany and modeled results with economic dispatch (blue dotted) and unit commitment (red) 66
Figure 45. Land-based value factor for different countries in the Likely scenario. Systems with direct access to hydropower are shown with dotted lines. 68
Figure 46. Development of value factors across scenarios in countries with large access to hydropower: Norway and Sweden 69
Figure 47. Development of offshore wind value factor in the three scenarios for Denmark and Germany 70
Figure 48. Estimation of LCOE including system cost in northwestern Germany (NW) and central and southern Germany (CS). System costs include balancing cost of 2 €/MWh and the profile cost from the resulting market value in the different simulations. Assumptions: 4% real discount rate, 30 years of lifetime, technology cost for the year 2030. 72
Figure 49. Full-load hour range for the different modeled regions in Europe for the two sensitivities. Average for Germany shown as columns. 73
Figure 50. Value factor development for the two sensitivities Sp175 and hh150, compared to the BaU and Ambitious scenarios 73
Figure 51. Illustration of the effect of subsidies at negative prices on the price duration curve. A price gap is formed on the lower part of the price duration curve, where RES are marginal producers. 81
Figure A1. Smoothing factor, K_w, for the different regions 91

List of Tables

Table ES1. Distribution of Cost Differences Compared to BaU on New Turbine Installation and Remaining System ix
Table 1. Low Wind Speed Turbine Models in the Market or Under Development by Main Manufacturers. Sources: [13] [14] [15] and OEM's datasheets. 9
Table 2. Parameters g and M Defining the Power Curve of the Technologies 28
Table 3. NTC in the German North-South Corridor (GW) 40
Table 4. What is an Input and What is a Result of the Scenarios? 41
Table 5. Annual Land-Based Wind Generation by Country and Year in Terawatt-hours. Last two columns indicate the land-based and total wind penetration with respect to power demand in 2030. 47
Table 6. Installed Land-based Wind Capacity by Scenario, Historical and New Installations 49
Table 7. Distribution of Cost Differences Compared to the BaU scenario on New Turbine Installation and Remaining System. Cost per megawatt-hour is calculated as total cost relative to generation from all new wind turbines installed after 2015 61
Table 8. Threshold Values for Increased Investment and Fixed Operation and Maintenance Cost Compared to the BaU Scenario. Threshold values are shown for the capacity installed and technology type applied in the given year (e.g., in 2020, turbines in the Likely scenario can be at most 34% more costly than BaU turbines before savings are offset; in 2025, new turbines can be at most 35% more costly, given that the turbines installed previously are 34% more costly). 61
Table 9. Relative Benefit in Terms of Additional Value per CAPEX Increase for the Two Sensitivities Compared to the BaU and Ambitious Scenarios in 2030 74
Table A1. Wind Plant Cost Assumptions 89

1 Introduction

1.1 Research Motivation

In the last few years, the European power system has seen some dramatic changes, especially with respect to generation technologies. In particular, the increasing penetration of variable renewable energy sources (VRES), such as wind power and photovoltaics (PV), is posing challenges to the current way power systems and power markets are operated.

In several European Union (EU) countries, the share of wind power covering the demand has exceeded 15%. In Denmark, wind power broke a record in 2015 for the share of electricity demand covered, reaching 42%. Germany has also seen an exponential increase in wind power deployment, with a total installed capacity above 50 GW at the end of 2016. The *Energiewende*, the German green revolution, is placing growing importance on the development of wind and solar, making higher penetration of wind certain in the coming years. Due to its large territory, limited access to the sea, and extensive land-based wind resources, the majority of Germany's wind power installations will be land-based.

Very high wind-penetration rates pose challenges to both the operation of the power system and the market function. Because wind power has almost zero marginal cost, it affects the supply curves and pushes the market equilibrium toward lower prices. This effect is known as the *merit-order effect*. Wind farms within the same region tend to produce simultaneously because the wind resource is geographically correlated; this causes the so-called *self-cannibalization effect*. With high wind shares, wind power producers see a market price that is lower than the average annual price because wind is pushing the price down in the hours they are producing. Another effect is the increased steepness of the residual load duration curves, leading to polarization of prices: low prices occurring during periods of high wind resources and high prices when no wind is blowing.

The price obtained by wind producers is normally referred to as the *market value of wind* or wind-weighted price. It is calculated as the ratio between the total annual market revenues[4] for wind generators and the potential annual wind generation (including curtailed energy).

The ratio between the *market value of wind* and the annual average price is often referred to as the wind *value factor*. To give an example, in 2015 the wind value factor in Germany was 0.85, meaning that wind producers saw a price in the market that was 15% lower than the average. Depending on the market and subsidy scheme design, this reduction of the market value of wind in the system might impact the income of wind producers and could have implications for the future investments in the technology—potentially endangering the green transformation of the power system.

With growing shares of VRES, three main system integration options can be distinguished [2]:

- Improved operating strategies (e.g., improved forecasting techniques, enhanced scheduling of power plants)
- Investment in additional flexible resources
- System-friendly deployment of VRES power generation in the power system.

[4] Wind power generation is assumed to be sold at the hourly wholesale market price.

The system perspective of the first two system integration areas is intuitive, and the importance of system integration of VRES is being increasingly acknowledged. However, the latter (e.g., individual site selection for renewable energy sources (RES) project development, technology selection, etc.) may be regarded specific to the choices of individual commercial RES power project developers.

In the last few years, the specific power of wind turbines, expressed as a ratio between electric power output and swept area, has been progressively decreasing. Based on the idea of larger swept areas and higher hub heights for the same rated power, new wind turbine designs are beginning to emerge. These so-called low wind speed turbines (LWST) produce more energy at lower wind speed, have a less volatile production, and show a general increase in annual full load hours (FLH). However, recent deployment of LWST is not necessarily linked to system benefits, but it can also be an advantage from a pure cost-of-generation perspective for individual developers.

Utilizing this new concept in the power system could allow more wind-generated electricity to be produced in periods of higher prices (i.e., when conventional wind turbines are producing less, and the merit order effect is less pronounced) thus increasing the value of wind. Moreover, higher capacity factors and more stable production could potentially decrease the total system costs. Therefore, this "*silent revolution*" in land-based wind power could potentially have a large effect in the system and should not be overlooked when projecting wind development in the future.

The ambition of the current study is to explore the effects on the system-wide value of wind arising from wind-turbine technology choices in the current and projected European power system. This study seeks to provide additional insights into the role of wind turbine technology, specifically on the pathway to successful system integration of increasing shares of RES power generation. These insights could, in turn, provide input to the discussion on socioeconomically beneficial designs of incentive schemes and regulations for RES deployment.

1.2 Contribution to Existing Literature

Along with the increasing role of wind power in power systems globally, the value of wind power has become an important topic of investigation. This is particularly true for countries and regions where wind power generation comprises a significant share of the total generation, such as Denmark, Germany, and the United States (on individual state level).

Existing literature on the value of wind includes studies on parameters influencing the market value of wind power [3], market value and impact of offshore wind on the electricity spot market [4], effect of solar and wind power variability on their relative price [5], strategies to mitigate declines in the economic value of wind and solar at high penetration [6], and many more.

The impact of the wind turbine design and technology trends on the value of wind is a more recent topic. A study by Nils Günter May [7] investigated the effect of support schemes on the technology choice, while research by Simon Müller and Lion Hirth [8] explored the market effects of different technology choices. The main result of the latter is that "advanced" turbine design (in terms of specific power and hub height) can significantly reduce the wind value drop at high penetration levels. Moreover, wind turbines designed in a more system-friendly way perform better than other integration measures in limiting decreases in value of wind.

The current study contributes to the existing body of knowledge with the following:

- Representation of the broader European interconnected power system;
- Presentation of a realistic future perspective because both the present and future state of the European power system are simulated (based on system-wide development projections), as opposed to varying the RES generation penetration levels in an unchanged system framework;
- Quantification of a likely evolution of the market value of wind in Europe is undertaken to increase awareness of the possible risks related to decreasing value;
- Focus on total system cost in the different scenarios and estimation of the capital expenditures (CAPEX) threshold to deliver system benefits;
- Contribution of the different wind turbine technology elements (specific power and hub height) are distinguished;
- The current study also distinguishes the existing wind power project fleet (which remains constant and is eventually decommissioned) from the envisioned future installations (the technological characteristics of which are being varied across a number of scenarios).

1.3 Trends in the Technology

Horizontal-axis wind turbine technology is constantly evolving. Some global macro trends can be identified in the continuous growth of rated power, rotor size, and hub height over time. Nonetheless, something more subtle is happening in the wind industry, which has been described as a “silent revolution.” This term has been used by Bernard Chabot in a series of articles and analyses [9] to describe the transformation happening in the land-based wind industry in the last few years.

Currently, most wind turbine manufacturers produce, or have announced plans to produce, models that are optimized for lower wind sites and generally classified as International Electrotechnical Commission (IEC) Class III[5]. Given constant power, a higher swept area enables a turbine to harvest more power at lower wind speeds. The specific power of these models is reduced in order to increase production and consequently boost capacity factors (CF).

The specific power of LWST available in the market is now less than 200 W/m^2, resulting in potential annual full-load hours up to or exceeding 4,000 hours—a level difficult to imagine for land-based wind power a few years ago. The specific power of newly-installed turbines has been dropping significantly due to LWST installations and a general reduction in specific power for turbines in high wind sites. In general, the growth in rotor diameter has outpaced the growth of the rated capacity of turbines.

[5] IEC classes are defined in IEC 61400-1 standard and describe the wind climate conditions that the turbine is suitable for. Class III turbines are designed for low wind speeds and appropriate for sites with a 50-year gust value of 52.5 m/s and average speeds up to 7.5 m/s.

In addition, turbine hub heights have been continuously increasing as better materials and improved tower designs allow for harvesting higher wind speeds at taller hub heights. In Germany, the tallest wind turbine erected in 2016 was a Nordex N131 with a hub height of 164 m, while the average hub height was around 130 m.

Figure 1 shows the historical development of specific power and hub height in Denmark, Germany, and the United States.

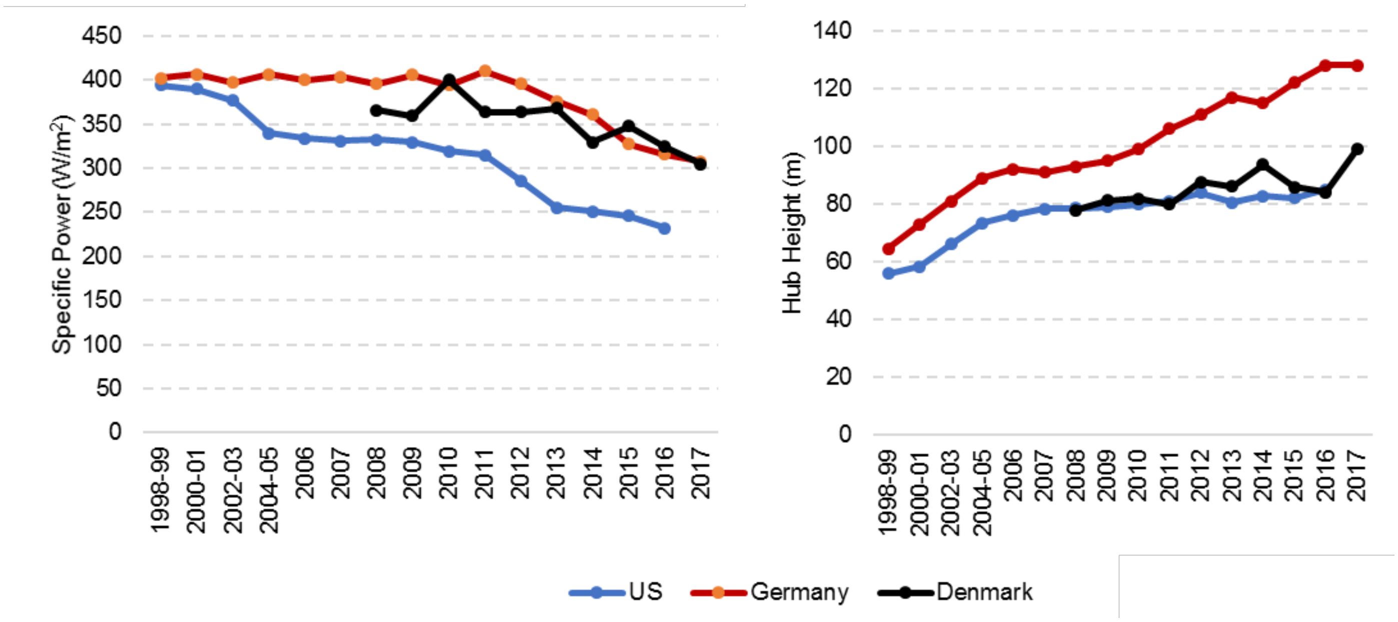


Figure 1. Historical development of specific power (left) and hub height (right) in the United States, Germany, and Denmark. Data for 2017 refer to the sample size available to date. Source: [10], [11], [12]

All LWST models described above were originally designed for low wind speed sites, corresponding to IEC Class III requirements. This should result in significant limitations for suitable sites for deployment. Nevertheless, in the United States, where the Class III turbines already make up the vast majority of new installations, LWST are now in widespread use in high wind sites as well [10]. A similar trend is evident in Germany where the specific power development is broken down based on the wind zone[6], as shown in Figure 2.

[6] Zones defined by DIBt (Deutsches Institut für Bautechnik) guideline for wind turbines: wind zone I (weak wind locations), wind zone II (typical inland locations), wind zone III (locations near to coast) and wind zone IV (coast line).

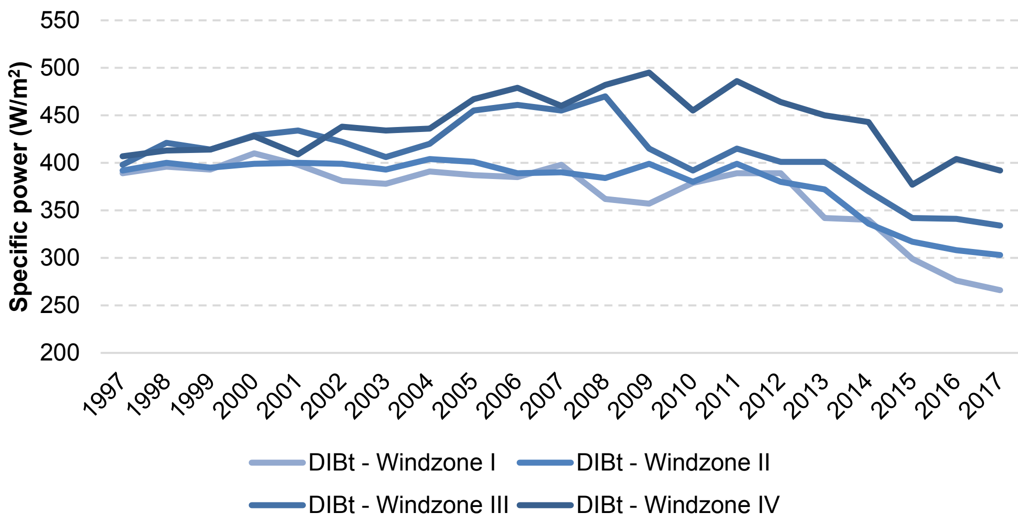


Figure 2. Specific power of newly installed turbines in Germany by wind zone. Wind zone I (weak wind locations), wind zone II (typical inland locations), wind zone III (near-coast locations), and wind zone IV (coastline). Source: [11]

Following the general reduction in specific power occurring in the last few years, it is conceivable that turbine models with reduced specific power will be available for higher IEC classes as well. The specific power can be reduced in the following two ways (or combination of these):

- Increasing the swept area: future improvements in blade and structure design should allow the limited swept area for Class I sites to be pushed forward;
- Decreasing the rated power of the generator: this could be an economically viable option when the value drop is significant. During high wind production, the self-cannibalization effect is at its highest, making the savings from a smaller generator more attractive.

Table 1 shows the latest land-based turbine models with their specifications, ranked from the lowest to the highest specific power. Where possible, information regarding available hub heights and rated wind speed has been added. The specifications are collected from manufacturers' websites and online databases [13] [14] [15].

Most of the turbines are categorized as IEC class III (A or B), but some low specific power models are starting to appear for IEC class II as well, confirming the trend described above.

Table 1. Low Wind Speed Turbine Models in the Market or Under Development by Main Manufacturers. Sources: [13] [14] [15] and OEM's datasheets.

Model	Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m^2)	Hub Height (m)	Rated Wind Speed (m/s)
Below 2.5 MW					
Vestas V120	2	120	**177**	Site specific	-
Vestas V116	2	116	**189**	Site specific	-
GE 2.0-116	2	116	**189**	80/94	10
Senvion 2.3M124	2.3	124	**193**	90 to 120	10
Gamesa G114	2	114	**195**	93/120/140	10
Gamesa G126	2.5	126	**200**	84 to 129	10
Siemens 2.3-120	2.3	120	**203**	80 to 93	11.5
GE 1.7-103	1.7	103	**204**	80	11.5
Vestas V110	2	110	**211**	80 to 125	11.5
Gw121	2.5	121	**216**	110/139	12
GE 2.5-120	2.5	120	**220**	91/120/141	11
NORDEX N117	2.4	117	**224**	80/94	10
Above 2.5 MW					
Gw140	3	140	**195**	100/120	10.5
Siemens 3.15-142	3.15	142	**199**	109/129/165	11
Acciona AW 132	3	132	**219**	84 to 120	-
Senvion 3.4M140	3.4	140	**221**	107 to 130	11
NORDEX N131	3	131	**223**	99/114/134	11.5
Vestas V150	4	150	**226**	Site specific	-
NORDEX N149	4	149	**229**	105/125/164	-
Alstom 122	2.7	122	**231**	89 to 139	10
Vestas V136-3.45	3.45	136	**238**	149 to 166	11
GE 3.2-130	3.2	130	**241**	85 to 155	12.5
Siemens 3.3-130	3.3	130	**248**	85 to 135	13

The effects of reduced specific power and increased hub heights are shown in Figure 3. A lower specific power turbine has a lower rated speed[7] and produces much more power at lower wind speeds. This is at the expense of production at higher wind speeds, which is capped by the reduced turbine rating. As an example, a Vestas V110-2MW has a rated speed of 11 m/s compared to 15 m/s for a V90-3MW and produces 70% more power at 8 m/s. The actual generation difference depends on how the turbines are configured and whether reduced specific power is achieved by reducing the generator rating, larger rotor, or both. A higher hub height increases the resource quality at hub height, shifting the probability density of wind speeds towards higher speeds.

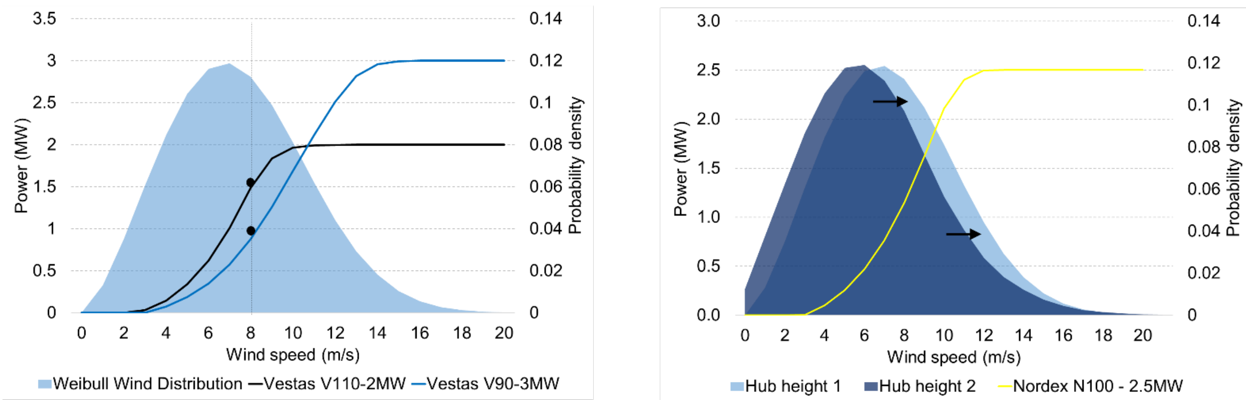


Figure 3. Illustration of the effect of reduced specific power (left) and increased hub height (right)

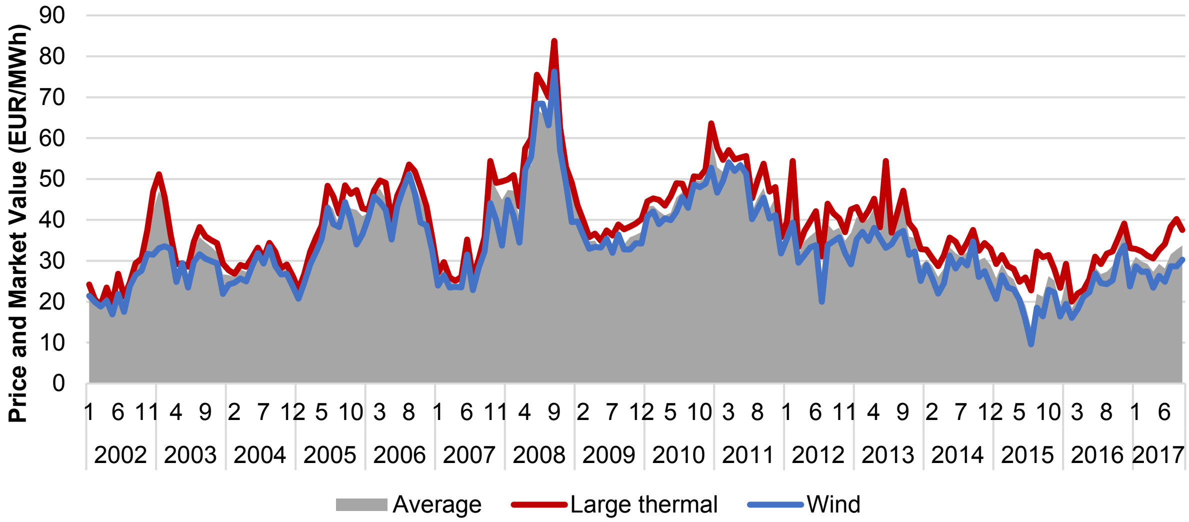
1.4 The Market Value of Wind

The market value of wind is a concept that is gaining importance in the international energy environment and it has been the focus of many recent publications and studies. Following the classical definition, formalized in [4] and [5], the market value of wind expressed in €/MWh is the ratio between the revenue of wind power in the market in a certain time period and its potential production, including curtailment[8]. It represents the average revenue per energy unit of wind produced. In order to capture the characteristic seasonal variation of wind, it is usually expressed in a yearly time frame. Market value is sometimes also referred to as wind-weighted price or wind capture price.

For a clearer picture and for ease of comparison, market value is usually expressed in relative terms, with respect to the average day-ahead market price (time-weighted). The wind value factor (VF) is defined as the ratio between the market value in a certain market zone and the average price of that zone[6]. The value can be specified for a country with different market zones as well. In that case, the average market price for the country considered is the system price (i.e., the average price weighted with the consumption in the different market zones). The value of wind represents the relative price "seen" by the wind producers in the market, with respect to the average system price. By focusing only on the market component of the wind producers' revenue, it excludes incomes from any support scheme potentially in place.

[7] The rated speed is the wind speed at which the turbine reaches the rated power. After that speed, the power produced is maintained constant.
[8] See mathematical definitions in the Glossary.

An example of the development of the market values and value factors in Denmark over the last few years is shown in Figure 4.



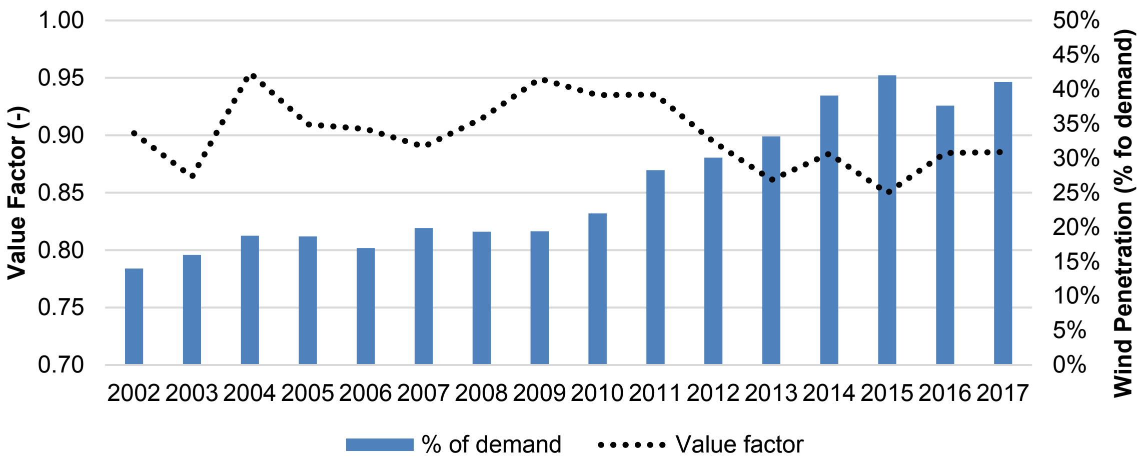


Figure 4. Development of price and market values of wind and large thermal plants (above) and value factor development in Denmark with respect to the wind penetration (below). 2017 data are based on data for January till September. Source: [16]

The first figure shows the development of the wholesale price in Denmark compared to the market values of wind and large thermal power plants. Wind "sees" a market price that is lower than the average price, while large power plants achieve a higher price. The second figure shows how the value factor, in relative terms, is developing over time and with respect to the penetration of wind power. When the penetration of wind is increasing, the value factor is dropping.

In markets that do not benefit from the access to Nordic hydropower, such as Germany, this drop has been much more dramatic—even at lower penetration rates. Figure 5 shows the development of value factors for Denmark, Germany, and Sweden as a function of the market share of wind.

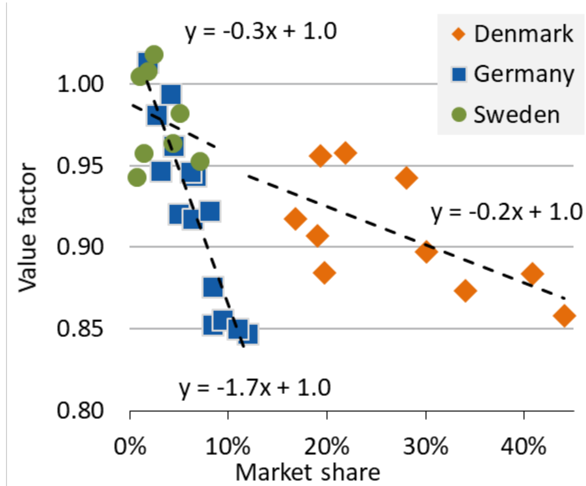


Figure 5. Value drop at increasing wind market share for Germany, Denmark, and Sweden, based on actual market data. Source: [17]

2 Wind Turbine Technology Scenarios

The scenarios analyzed and the sensitivities performed in the study are presented in this chapter.

2.1 Analysis Focus and Scenarios Setup

The present analysis focuses on the evolution of the system value of wind power under different wind turbine technology scenarios. To assess the system value of wind, both total system costs and market value of wind are analyzed.

The effect of the wind turbine technology on the value of wind for the European power system is evaluated in three different scenarios from the current point of time to 2030. The scenarios differ by the type of wind turbine technology for all future wind power installations (Figure 6). The remaining system can adapt to those changes in terms of investments and generation patterns, but all underlying assumptions for the framework conditions remain the same (see Chapter 4). The annual wind generation across the different scenarios is the same. In other words, a change in capacity factor of turbines results in a change of installed capacity and not in a change of total generation.

- **BaU:** Characterized by a deployment of wind power technology in line with the characteristics of today's newly installed turbines in Europe, namely specific power of 325 W/m^2 and hub height of 100 m.
- **Likely:** Considers a turbine technology which will likely characterize the European situation in 2030, specifically a specific power 250 W/m^2 and hub height of 125 m. The projection of the characteristics is based on the expert elicitation survey conducted within the framework of IEA Wind TCP Task 26 [1].
- **Ambitious:** Represents a very aggressive development in terms of both specific power and hub height across Europe, with values of 175 W/m^2 and 150 m hub height.

A reference simulation is performed for the year 2015 and subsequently, three technology scenarios are simulated up to 2030 in 5-year increments. In each of the scenarios, the same wind power technology for new installations is applied across all years and all countries. In reality, the applied wind power technology will vary both over time, with more advanced turbines being more common in the late stages of the period, and over the geographical area as different technologies will be the most suitable for different site conditions. These factors have not been taken into account to enable a simple scenario setup.

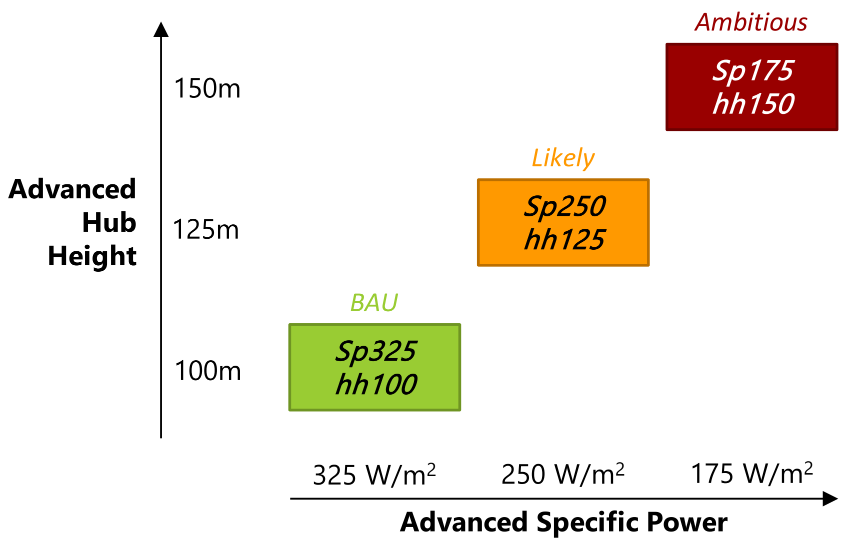


Figure 6. Scenario setup for the analysis

2.2 Sensitivity Analyses

Two sensitivity analyses are performed to understand the effects of the single parameter variation on the results. With the BaU scenario as a starting point, only the specific power is decreased in the first sensitivity and only the hub height is increased in the second sensitivity (Figure 7).

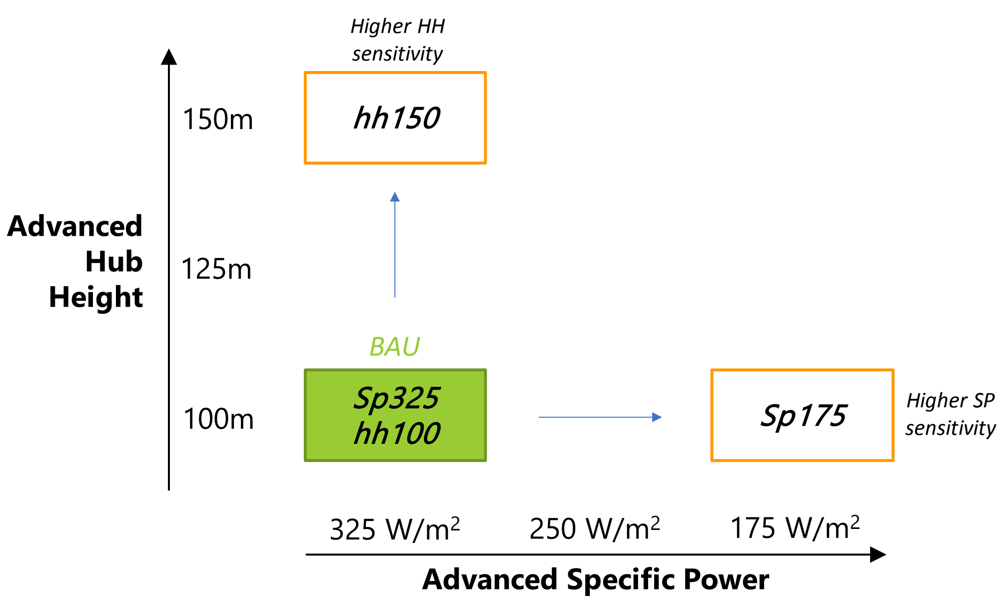


Figure 7. Setup of sensitivity analyses

3 Methodology

This chapter presents the model used for the analysis, the simulation setup, and the wind generation modeling.

3.1 The Balmorel Model

Balmorel, the "*BALtic MOdel of Regional Electricity Liberalized,*" is an open-source model for analyzing the combined power and heat sector in internationally integrated markets[9]. The model is coded in the General Algebraic Modeling System (GAMS), which is a high-level modeling system for mathematical programming and optimization.

The model is highly versatile and has been successfully applied for long-term planning and scenario analyses, and short-term operational analyses on both international as well as detailed regional levels. It has been used by several institutions and companies, including Ea Energy Analyses, Technical University of Denmark (DTU), Tallin University of Technology, Norwegian University of Life Sciences (NMBU), Elering (Estonian TSO), the Danish Energy Association, Grøn Energi, and HOFOR. A large number of projects have been carried out, most of which are related to the Danish, Nordic, and European combined heat and power systems. In addition, the Balmorel model has been applied in Mexico, Vietnam, China, Western Africa, South Africa, and Eastern Africa.

Balmorel is a bottom-up, linear, and deterministic model, with the possibility for both investment and dispatch optimization. The model can calculate generation, transmission, and consumption of power and heating on an hourly basis, as well as optimize the electricity, heat, and transmission capacity in the system.

The model has various simulation setups when performing an Economic Dispatch optimization. The main setups are as follows:

- **Operation and Investment Optimization**: the optimization is formulated as a linear problem (LP). It includes the possibility to invest endogenously in generation capacity and the outcome is a result of a joint optimization of operations and investments. New capacity is added to the system if the revenues from operations can at least cover the investment cost, while a plant is decommissioned if no longer profitable. Regarding resolution, only specific selected timesteps are simulated.
- **Operation optimization with hourly resolution for a week at a time, considering unit commitment**: the problem is formulated as a relaxed mix integer problem solved by optimizing operations and dispatching the cheapest generation, considering the start-up costs and minimum load of units. The time horizon for the optimization is a single week. When running hourly simulations for a year, this corresponds to 52 weekly optimizations. The main difference compared to having a one-year time horizon lies in how storage and hydropower operations are optimized, having a much lower time horizon to perfect knowledge. The capacity installed is an exogenous parameter.

[9] Available at www.balmorel.com.

The simulation setup in the current study is based on investment optimization, followed by dispatch optimization with hourly time resolution (see Section 3.2 for further details). An overview of the model characteristics is shown in Figure 8.

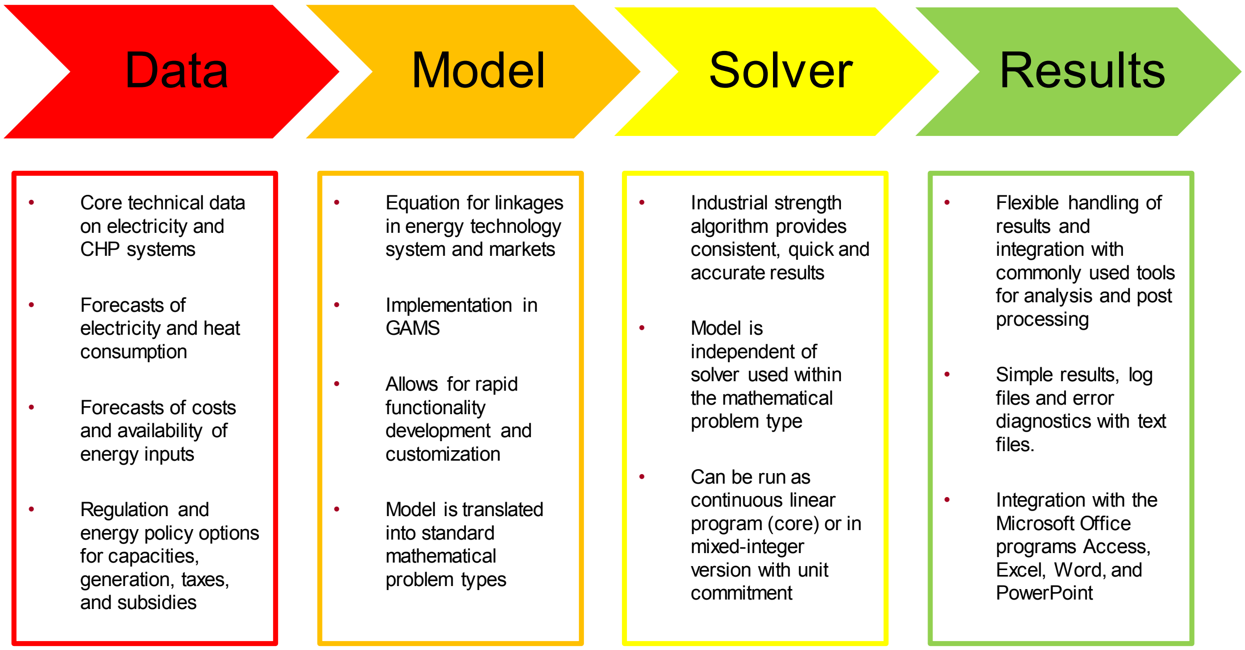


Figure 8. The Balmorel Model characteristics: infographic regarding data, model, solver, and results

The geographic scope of the model is flexible depending on the availability of input data, such as generation fleet, transmission capacities, and load profiles. For this study, the following countries have been included in the analysis: Austria, Belgium, the Czech Republic, Denmark, Estonia, France, Finland, Germany, Italy, Latvia, Lithuania, the Netherlands, Norway, Poland, Sweden, Switzerland, and the United Kingdom (Figure 9).

The model includes a detailed representation of the Nordic countries, Baltic countries, and Germany, including district heating areas, and the level of detail is down to the single plant. The rest of the countries are represented in a more aggregated fashion.

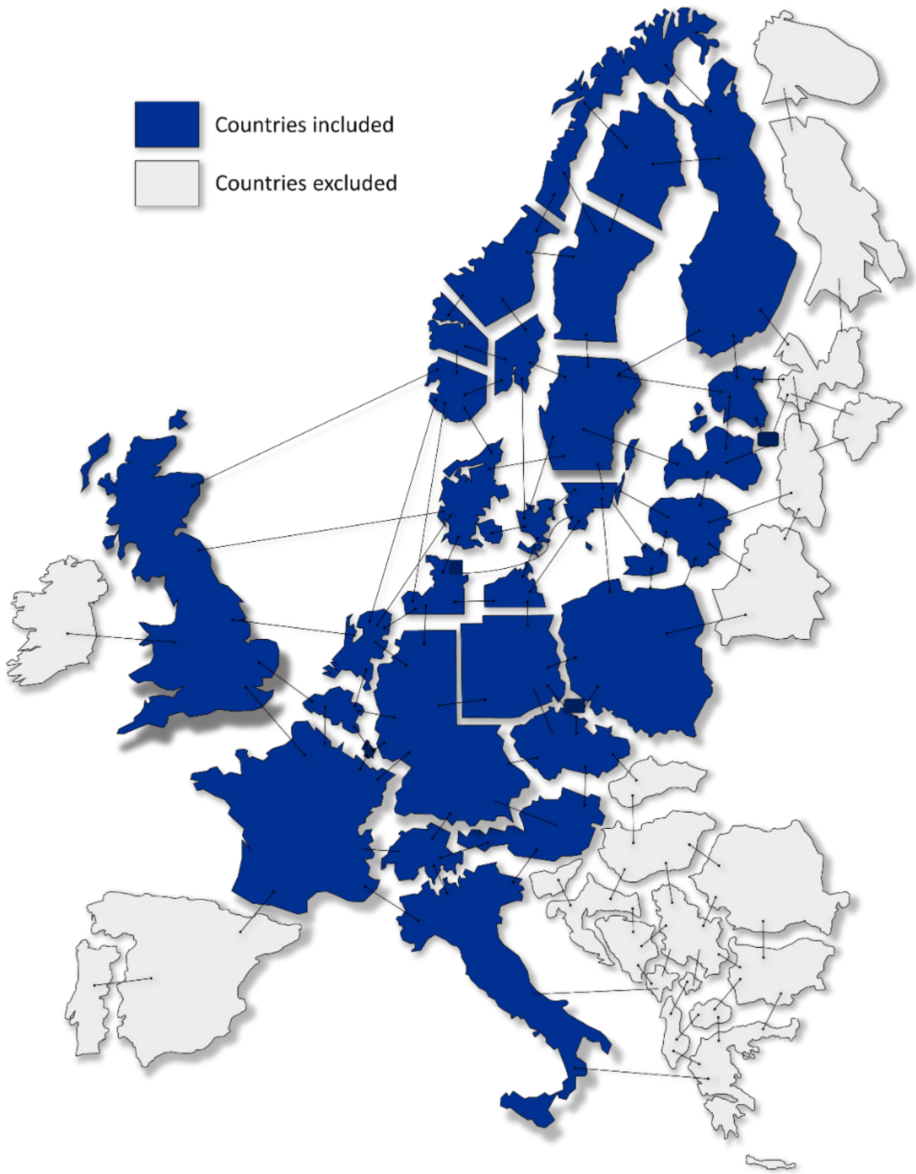


Figure 9. Geographic scope of the model and of the current analysis

3.2 Simulation Setup

Regarding the simulation setup, a first reference simulation is performed for the year 2015. A common framework is then established with general assumptions regarding fuel and CO_2 price projections, transmission expansion, exogenous development of renewable energy sources for electricity (RES-E), and all other model assumptions. Consequently, the simulation steps are as follows.

Investment run for each technology scenario and year: set the capacity of the specific wind technology to fulfill the annual target and enable the system to adapt and optimize by means of new investments and decommissioning. Resolution is reduced by means of *time-aggregation*, with a total of 12 weeks simulated in the model, each composed of six representative hours. The investment run defines the available capacities in the system, and these capacities are subsequently used in the dispatch run. Furthermore, the seasonal value of hydropower is calculated. In this time-aggregated run, the usage of hydropower and its value to the system is optimized, taking into account the available inflow and storage capacities. Maximum and minimum storage capacities in the model are subject to seasonal variation, estimated based on historical usage of storages. In order to represent hydro operators' assessment of future value of hydro generation, the run assumes an additional cost of operating storages close to its limits.

Dispatch run for each technology scenario and year: import the result from the respective investment run (system configuration and seasonal value of hydropower) and optimize the dispatch over a year, considering Unit Commitment. Dispatch of hydropower plants with reservoirs is done according to the value of hydropower estimated in the investment run. The resolution is 8,736 hours, corresponding to 52 weeks (hourly temporal resolution). The time horizon for the optimization is one week.

Investment optimization simulations are characterized by high computational demand and a reduced temporal resolution is usually required. In Balmorel, the simulation features both a selected number of weeks per year and a reduced number of hours per week, chosen as a representative for investment decisions. The temporal resolution is of great importance when modeling VRES systems and their market value. Only detailed hourly representation of the dispatch can highlight the complex interaction of wind, demand, and other generators in the market. In addition, the higher the temporal resolution, the lower the estimated market value of wind energy. This is because more extreme events, which are only present in the high-resolution cases, have particularly strong price effects [18].

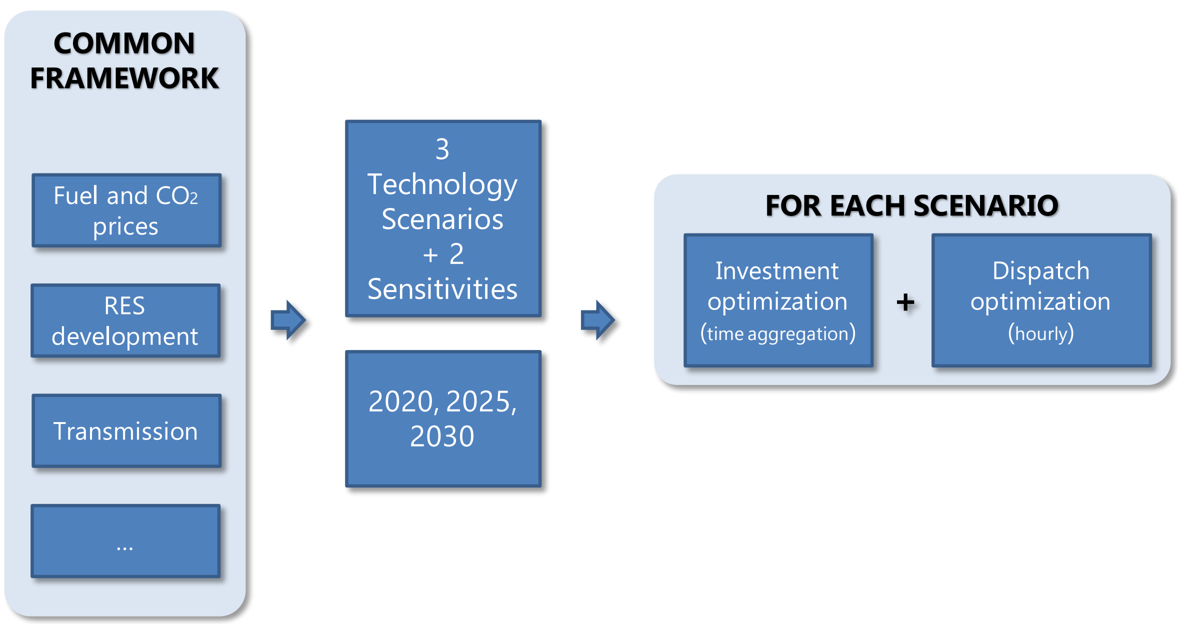


Figure 10. Simulation setup in terms of common framework and specific scenario runs

3.3 Modeling of Wind Power Generation

A number of topics are important to consider when modeling wind power generation. The importance of each aspect depends on the application. In this case, a good representation of wind power generation at the overall system level is desired, as opposed to modeling individual sites. In the applied modeling framework, wind generation at an hourly time resolution within a market area is important for the results (see Figure 9 for all market areas). The modeling approach is described for the following topics:

1. Basic representation of wind power in Balmorel to ensure representation of generation pattern characteristics (see Section 3.3.1)

2. Wind speed data across Europe to ensure representation of spatiotemporal correlation of wind speed and wind power generation (see Section 3.3.2)

3. Estimation of aggregated power curves representing generation patterns of an aggregated fleet within a market area (see Section 3.3.3)

4. Explicit modeling of the current and future wind turbine fleet and effects of aggregation across a wide geographical area in order to represent turbine design development (see Section 3.3.4).

The effects of turbine design on sub-hourly generation patterns and at a geographical scale below the modeled market areas have not been studied. Additionally, inter-annual variation in wind power generation as a result of the wind resource variability and the possible effects of wind turbine design have not been considered.

3.3.1 Wind Power in Balmorel

In the Balmorel model, wind power is modeled through wind speed profiles and aggregated power curves. Each modeled region is assigned a wind speed time series at a specific hub height from a representative location, which defines its resource quality, and a regional power curve is used to transform wind speed into wind generation.

To account for different potential hub heights of the turbines, the wind speed time series is extrapolated to higher or lower height using the power law, an empirical equation used in academia and industry:

$$u_2 = u_1 \cdot \left(\frac{h_2}{h_1}\right)^{\alpha}$$

where u_1 is the wind speed at height h_1, u_2 is the wind speed at the new height h_2, and α the wind shear factor. The shear factor is defined for each modeled region based on its roughness conditions.

An overview of the modeling approach is shown in Figure 11.

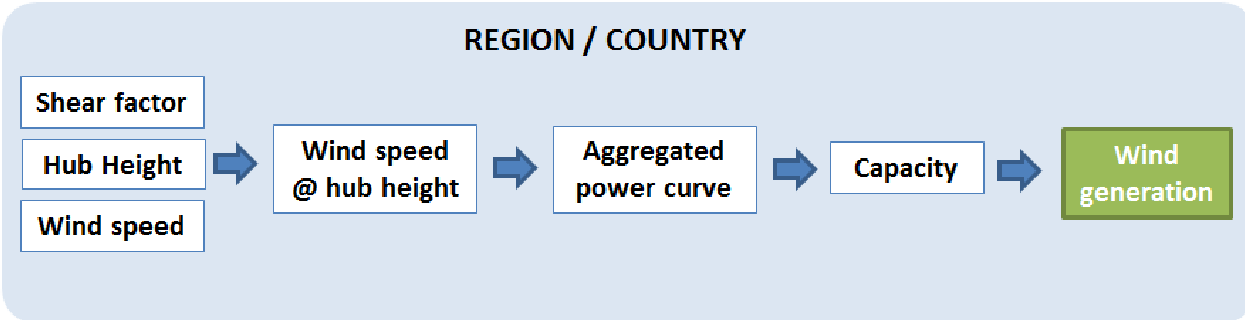


Figure 11. Principal wind power modeling in Balmorel. Aggregated power curves are defined for the existing wind power generation fleet and future wind power vintages separately.

Text Box 1. Precision of the representation of countrywide wind fleet production through aggregated power curve

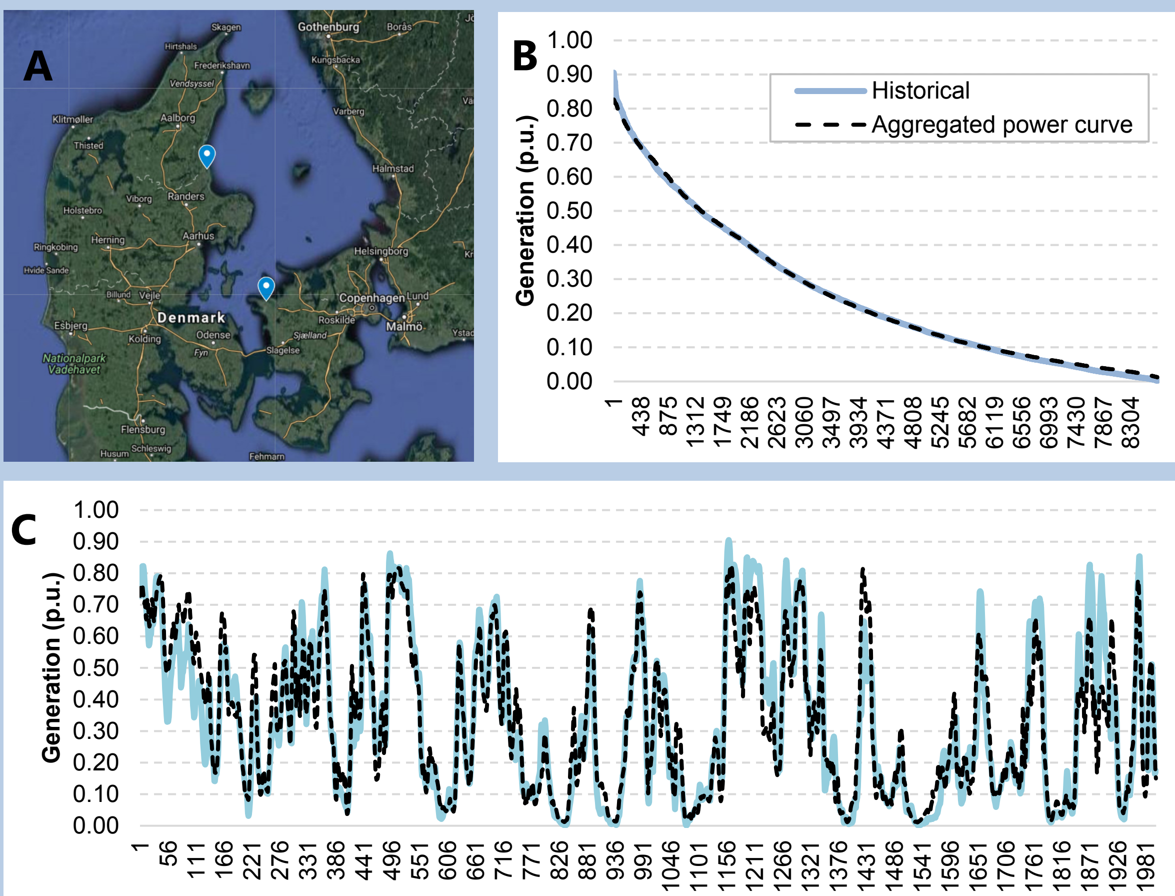
Denmark Example
In order to show how precisely the wind generation can be modeled by using a reference location and a regionally aggregated power curve, the result of the calibration for Denmark is displayed here.

Historical generation data for land-based wind is taken from Energinet.dk [16] and generation in *per unit* (p.u.) is calculated assuming linear growth of capacity from the beginning to end year.

Two representative wind locations for the wind speed time series of 2014 are chosen, one on DK1 and one in DK2 (Figure A). The aggregated power curve is calibrated based on realized generation data from the same year.

The comparison between realized and modeled time series reveals good accuracy. The shape of the duration curve is maintained (Figure B), which is the most important aspect when modeling wind in energy system analysis. Moreover, the root mean square error of the full time series is 8.7% and the hourly variations are well aligned (Figure C).

Using one time series to model a regional wind fleet reduces the complexity and computational time while offering a satisfying representation of the wind characteristics.



3.3.2 Wind Speeds in the Model

Growing interest in wind energy deployment and the need for accessible wind speed data have emerged in the past few years, in particular for power system and integration studies.

Reanalysis data sets are one source of time series data for different parameters (e.g., irradiation, surface temperatures, and wind speeds) produced by numerical weather prediction (NWP) models based on satellite observations and other weather observations. The latest generation of reanalysis data sets have become available in the last several years and they are gaining popularity due to their convenience and global coverage. The leading ones are CFSR-NCEP, MERRA, and ERA.

As underlined in [19] and other studies using reanalysis as a source for wind speed data, a systematic bias has been found in the value of reanalysis wind speeds, which may be able to replicate output pattern over time but do not accurately represent the overall resource level across space. To overcome these biases, a methodology to correct the wind speed has been developed by JRC in the new EMHIRES data set [20]. This methodology uses statistical spatial downscaling of hourly wind speeds from reanalysis data (MERRA as primary data) using microscale Weibull parameters derived from the Global Wind Atlas developed by the Danish Technical University [21].

This study uses the wind speeds underlying the EMHIRES data set for selected locations around Europe. As mentioned above, the Balmorel model uses aggregated power curves for each region or country applied to a reference wind speed location, which has to be identified.

The criteria used to select the representative location in each modeled region across Europe are the following:

- Using the layer of average wind speed at 100 m from Global Wind Atlas, the average wind speed is calculated in tiles of 10 km^2
- Inside the boundary of each modeled region, a location with the 3rd quartile of resource quality (corresponding to the 75% best wind location) in terms of average wind speed is selected as representative for the region.

The selection of the location with the 3rd quartile of wind resource is meant to represent the fact that, on average, some of the best wind spots are excluded from wind turbine installation due to orography of the terrain, population density, or environmental limits. Moreover, in regions with higher installed capacities, locations with lower average wind speeds are gradually deployed once the best spots are taken.

The locations selected are shown in Figure 12. Inherently, modeling of wind power in regions that cover a smaller geographical area will be more precise than in large areas. To offset this disadvantage, the locations for wind speed used in the smoothing calculation (see Section 3.3.4) are chosen to represent the relevant areas within a region. Reducing the area size is expected to improve modeling of wind power, but the calibration against historical data done here shows acceptable results (see Text Box 1).

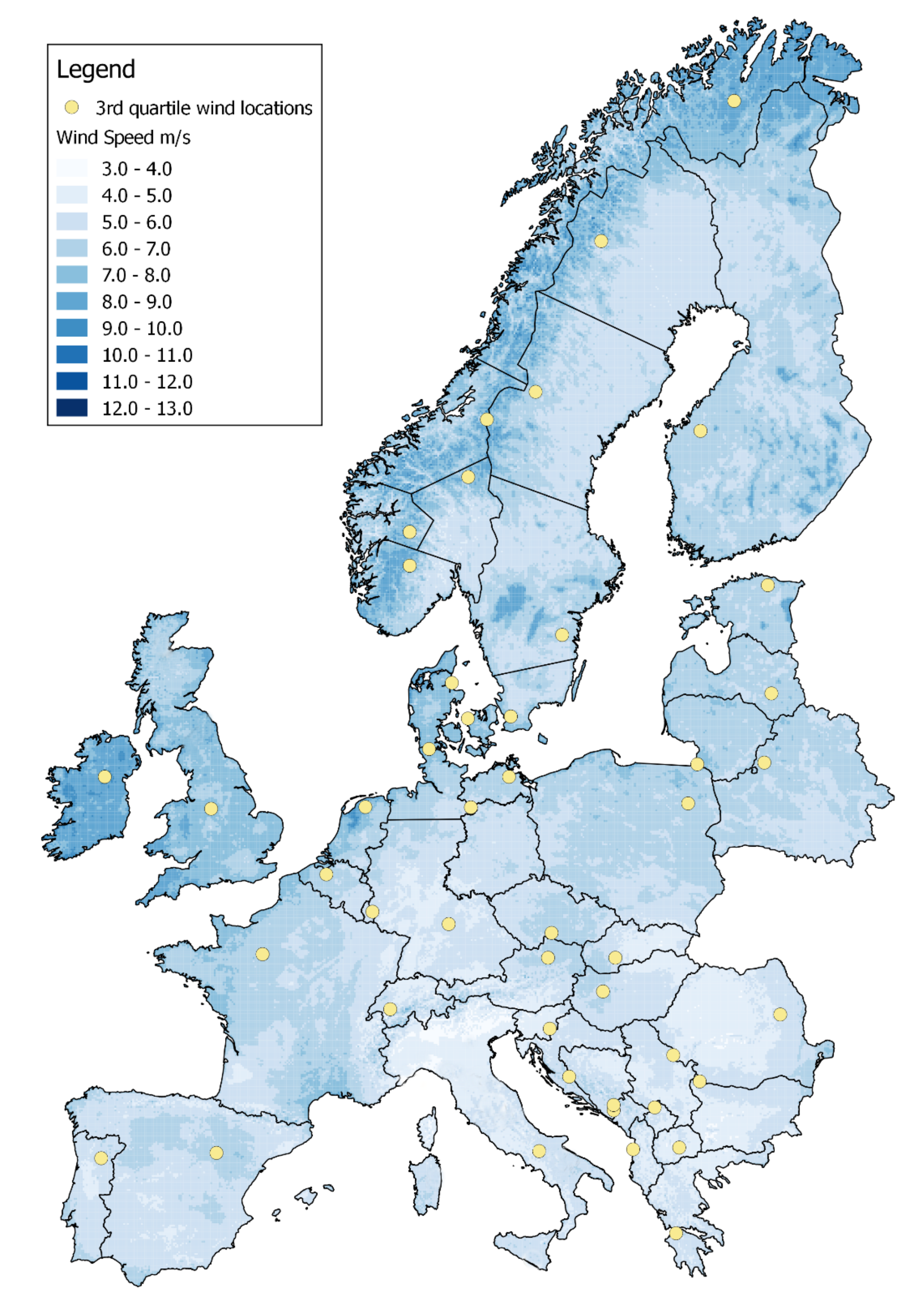


Figure 12. Average wind speed map and land-based locations selected for each Balmorel region

Notably, in regions where the average wind speed is low (below 6.8 m/s), the wind speed time series is adjusted to be representative for the 90% best wind conditions, underlying the assumption that regions with scarce wind resources still have unexploited potential at higher resource quality, and that the lowest quality wind sites would not be relevant for wind power deployment. For offshore locations, wind speed from MERRA reanalysis data are extracted and used for selected offshore areas.

To choose the representative coordinates for the offshore areas, an analysis of existing and planned offshore wind farms is carried on in the database *4C Offshore* [22]. The criteria to select the representative location for each offshore area includes: amount of capacity already installed (e.g., largest operational wind farm), areas made available for future tenders, and size of the areas in terms of potential megawatts for proposed or developing farms in the region. Therefore, both existing and new wind locations have been taken into account.

Most of the locations feature an average wind speed in line with the one reported in the *4C Offshore* database; however, the Italian offshore time series was much lower, and therefore is corrected using the methodology from EMHIRES.

Figure 13. Offshore wind locations represented in the model (northern Europe)

3.3.3 Conversion to Power – Aggregated Power Curve

The Balmorel model allows for the implementation of different wind power technologies. For each technology, technical aspects such as the power curve and hub height, as well as costs, are expressed.

Since the implemented technologies describe not only a single turbine, but a fleet of turbines, the conversion of wind speed is performed with an aggregated power curve. The aggregated power curve represents an equivalent regional power curve that is meant to describe the behavior of a fleet of turbines, rather than a turbine in a single location. A number of effects determine the shape of the aggregated power curve compared to one from a single turbine:

- Technological mix: a large range of turbine models are installed in the system and each of them has different production at the same wind speed
- Spatial averaging of production: turbines are spread through the considered wind area, therefore, they will not all experience the same wind speed as the one expressed for the representative location
- Array efficiency and wake losses
- Availability of turbines.

To describe the aggregated power curve, the model implements a modified logistic function equation:

$$P = \frac{\gamma}{1 + e^{(-g * K_w * (u - M - \epsilon))}}$$

Where:

- u: wind speed at hub height,
- γ: maximum power output reached in p.u.,
- M: wind speed at which the maximum slope is reached,
- g: maximum slope of the logistic curve,
- K_w: smoothing parameter to account for wind distribution in the region,
- ϵ: offset in the speed to represent the effect of real output compared to theoretical power curve from manufacturers.

These parameters are specified for each wind power technology. In addition, the hub height of the technology is defined and it represents the height at which the wind speed is extrapolated.

A general distinction between technologies is based on whether the technology represents historical capacity or future additions. This is also reflected in how the power curve is modeled (Figure 14). In practice:

- **Historical technologies**: describe wind turbines already installed in the system. Characteristics and costs are based on realized data. One specific technology for each country or region is defined and the parameters are calibrated to the realized time series for each country.

- **Future technologies**: represent options for future installations and are categorized based on their specific power. These technologies are defined universally across the countries in the model. A dedicated approach for the elaboration of aggregated power curves for each region is developed (see Section 3.3.4).

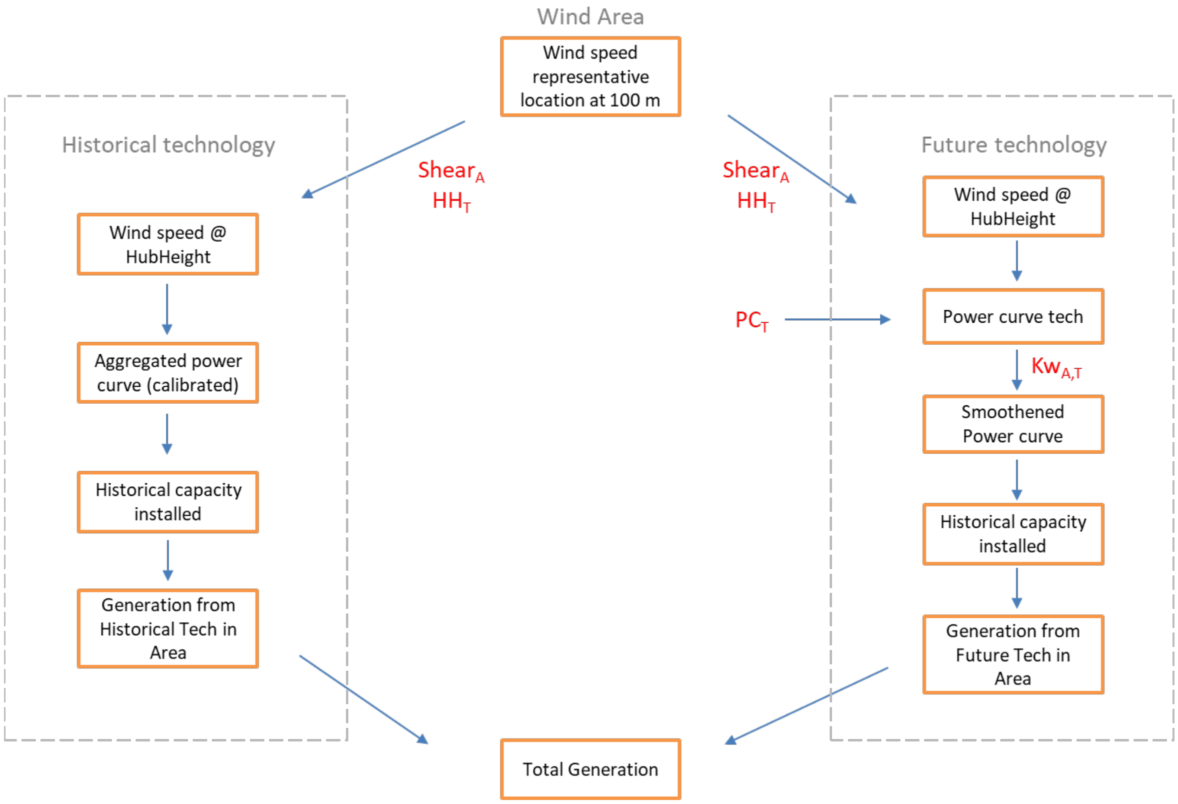


Figure 14. Modeling of wind-to-power module, historical, and future technology. Index *T* represents the different technologies, while *A* represents the wind areas.

3.3.4 Future Technology Modeling – Smoothing of Power Curves

First, turbines that represent the three specific power classes have to be selected. An analysis of power curve data from a variety of sources [13] [14] [23], which all derive the data from manufacturers' data sheets, is carried out. No large deviations have been found among turbines with the same specific power. A GE 2.75-103 (330 W/m^2) turbine was selected for the BaU scenario and a Siemens SWT 3.3-130 (249 W/m^2) for the Likely scenario.

The only turbine with a specific power comparable to the one in the Ambitious scenario is the Vestas V120-2MW (177 W/m^2), which is still under development and no power curve is yet available. Therefore, a synthetic power curve is generated, based on a Gamesa G114 with a reduced rating equal to 1.8 MW.

It is clear from Figure 15 that the lower the specific power is, the earlier the power reaches its nominal value (1 p.u.), meaning that the rated wind speed is lower.

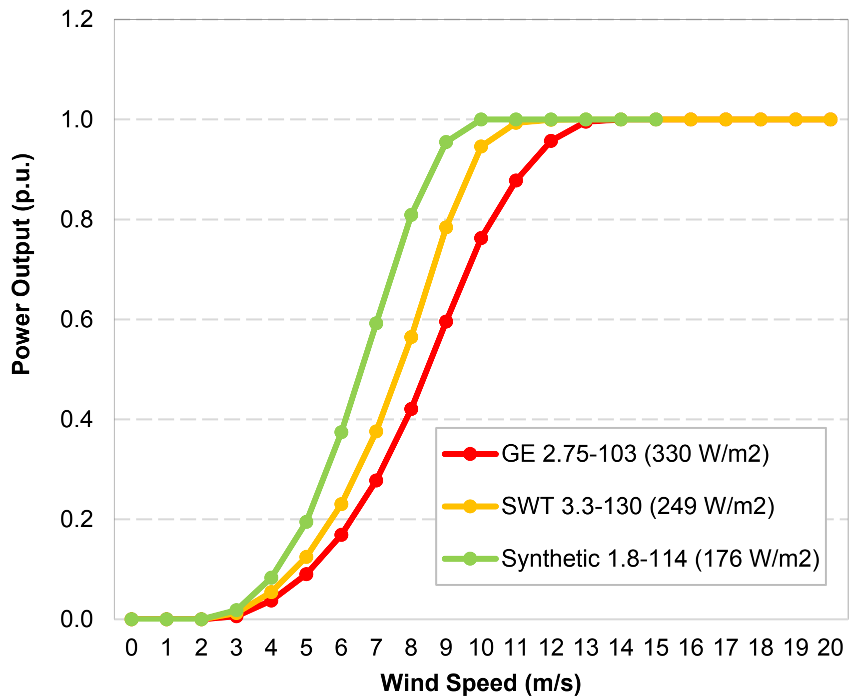


Figure 15. Power curves selected for the three main scenarios

In order to create aggregated power curves from the brochure ones above, a smoothing procedure is developed. The methodology is based on the idea of the *Multi-turbine power curve approach* [24], which suggests using a convolution between the power curve for a single turbine and a normal distribution of speeds to smooth the power curve and its production.

The steps that lead to estimating the parameters in the equation are the following:

1) Reference power curve from producers' specification corresponding to certain specific power are selected

2) Parameters *g* (growth rate) and *M* (maximum growth) are chosen to represent the reference curve with a logistic function

3) Wind offset considered (parameter ε) to express "real" production compared to production from the reference power curve

4) Wind speed time series for multiple locations in a region are chosen

5) *Total generation* is calculated as sum of the production from turbines in each location across the region and plotted (scatter-plot) with respect to the reference wind time series

6) Calculation of the parameter *Kw*, which describes the modification of the growth rate to account for the smoothing, in order to minimize the total hourly difference between *Total generation* and wind production from the smoothed power curve applied to reference wind time series.

Figure 16 visually describes the procedure.

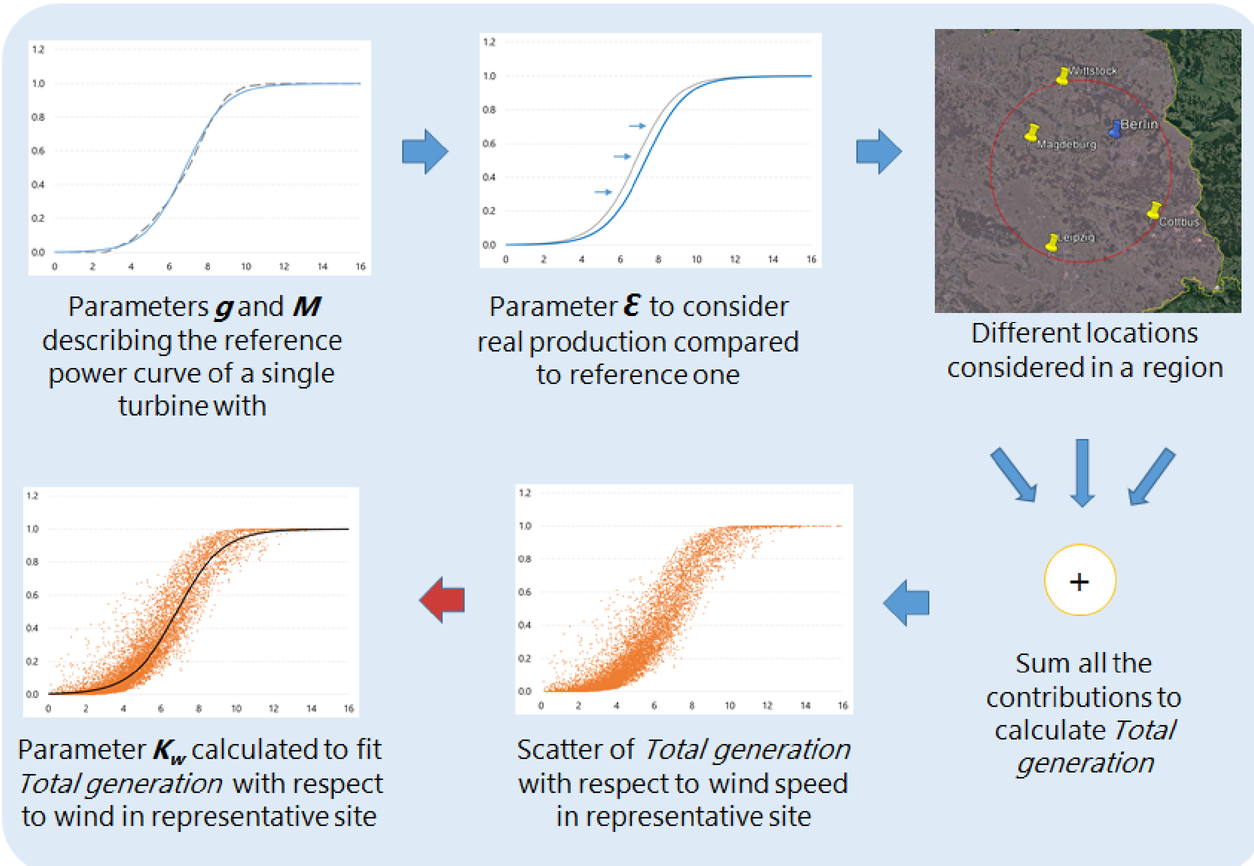


Figure 16. Smoothing procedure example—from reference to smoothed power curve

An interesting result is that the smoothing of the power curve does not only depend on the area considered, but also on the technology. Because lower specific power results in a steeper power curve, a deviation from the wind speed in the reference location can cause a large variation of power output, ultimately resulting in a smoother power curve. The process described is repeated for every combination of specific power technology and Balmorel region, in order to obtain the parameters that define the regional aggregated power curves and input them into the model.

The parameters g and M for the three technologies of specific power, computed to fit the reference power curves from manufacturers, are summarized in Table 2.

Table 2. Parameters g and M Defining the Power Curve of the Technologies

Parameter	Symbol	325 W/m^2	250 W/m^2	175 W/m^2
Growth rate	g	0.729	0.849	0.992
Max growth	M	8.38	7.48	6.52

The parameter ε, an offset of the wind speed seen by the turbine, is chosen to represent the "real" production from the turbine compared to the reference one. This effect is caused by reduced air density, imperfect control of the pitch and the yaw, electrical losses, wake effects, and other factors, all of which contribute to a reduction in the realized output. A visualization of the effect is shown in Figure 19, based on simulations carried out in [25][10].

A value of $\varepsilon = 1.2$ m/s results in a yearly performance ratio (corrected output divided by output from reference power curve) in the range 0.65-0.75, which is in line with other findings from both [25] and [26]. Furthermore, the offset is equal to the one used in [27] and close to the 1.27 value used in [28].

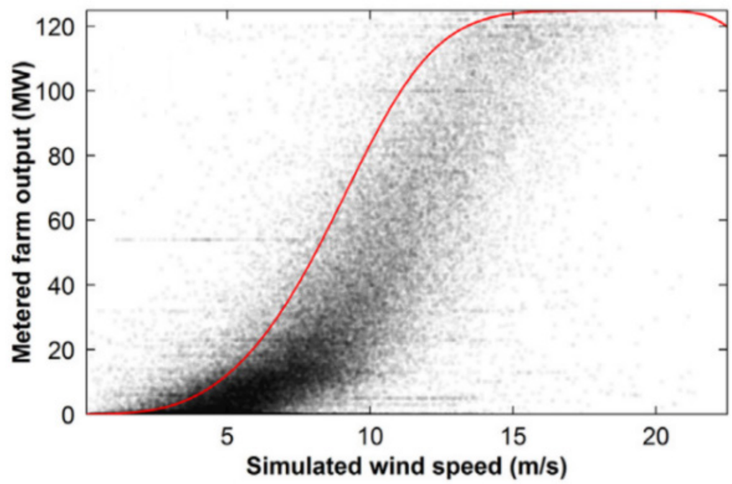


Figure 17. Example of metered wind farm output compared to theoretical power curve. Source: [25]

Finally, the values of K_w for the different regions, ordered by size (area of the region), are shown in Appendix 2. A lower value of K_w is related to a more smoothed power curve, due to the increased diversity in the wind speeds in the area. The main factor influencing it is the correlation of wind speeds in the area considered. Looking at the results, the parameter is lower in larger regions (right side of the graph). Moreover, as already mentioned, lower specific power results in a more smoothed aggregated power curve.

Given the smoothing procedure for newly introduced technologies and the effect of increased hub height, the resultant FLH for the different regions in the model, based on the wind speed time series described above, are shown in Figure 18 for the BaU and Ambitious scenarios, alongside a box plot with the distribution of FLH across regions.

[10] Note that Figure 17 shows two effects that explain the deviation between simulated and metered wind farm output: the impact of "real" generation compared to theoretical generation, and the impact of using simulated NASA wind speeds instead of measured wind speeds. Therefore, the difference between simulated and real output is larger than a *ε-factor* of 1.2 m/s would suggest.

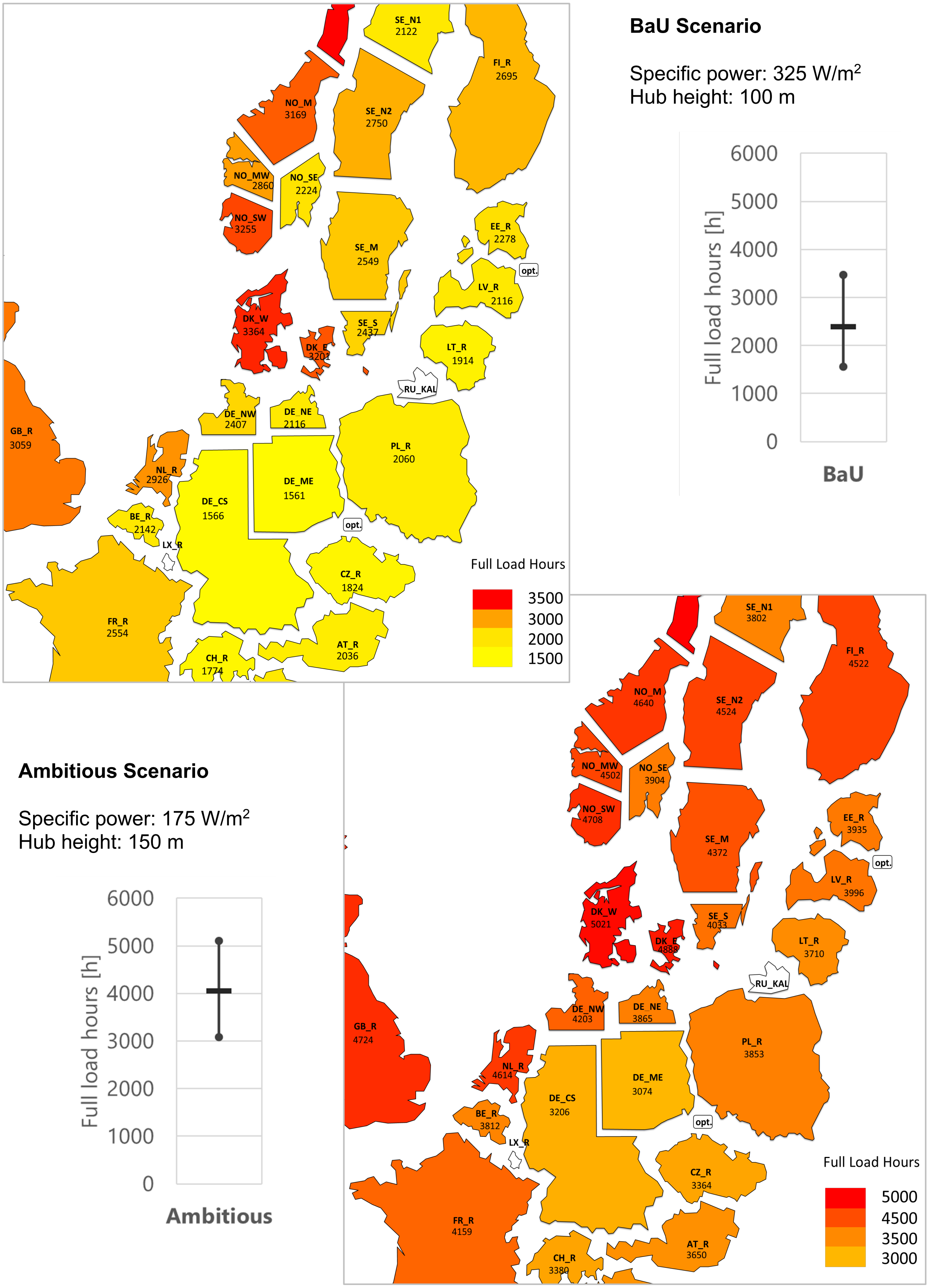


Figure 18. Full load hours comparison between BaU and Ambitious scenarios

4 Model Input Data and Assumptions

The development of the European power system depends on a range of parameters, including the development of fuel prices, the level of ambition for climate targets, technology costs, and regulations. All of these parameters will affect the composition and operation of the power system, and in turn affect optimal technology choices for wind turbines. In the current study, the aim has been to set up a Likely scenario for the European power system, acknowledging that model input data and assumptions are subject to large uncertainties. Text Box 2 summarizes the main approach to the development of central parameters.

Text Box 2. Main drivers for power system development and respective best estimate

Key factor	Our best estimate
How will fuel prices develop?	Climate policies and technological development will dampen the demand for fossil fuels. Hence, current low forward prices will converge toward the IEA's 450 ppm scenario from World Energy Outlook 2016.
What climate targets will the EU and its member states pursue for 2030 and beyond?	The EU will pursue an active climate policy, also beyond 2030. Some eastern European member states will be less ambitious.
Will renewable energy technologies mainly be supported through subsidies or indirectly by means of a carbon price?	The future climate policy will involve a combination of renewable energy support and carbon pricing. Until 2030, the importance of carbon pricing will still be moderate.
How will technological development influence power markets? • *Cheaper solar PV and offshore wind* • *New storage technologies* • *Flexible electricity demand and smart grids*	Investment cost of renewable energy technologies will decrease to the extent that their production profile becomes the major barrier for further market uptake. New storage technologies and smart grid technologies will not have major deployment towards 2030, but can gain increasing importance towards 2050.

4.1 Existing System: Generation and Transmission

The existing power system is described in the Balmorel model with different levels of detail. For the Nordic countries, particularly Denmark, the resolution is down to each large combined heat and power plant. Germany is described in great detail, including the main district heating areas in the country. For other European countries, generation data are aggregated in groups of plants by fuel and efficiencies. Beside ENTSO-E's transparency platform and data portal, many different country sources and TSO reports have been used as a source for the generation capacities.

Wind and solar data are updated to the end of 2015, based on *The Wind Power database* and *IEA PVPS* report. The decommissioning of the historical wind fleet is calculated by assuming a lifetime of 20 years from the commissioning year and is modeled in an aggregated way.

Data regarding the transmission system are adapted from ENTSO-E net transfer capacity figures to the Balmorel modeled regions, as well as from updated information from various national sources.

Text Box 3. Capacity by fuel in the modeled countries: existing system

	Austria	Belgium	Czech	Denmark	Estonia	Finland	France	Germany	Great Britain	Italy	Latvia	Lithuania	Netherlands	Norway	Poland	Sweden	Switzerlar
Oil	106	9,999	1,118	982	0	1,653	8,779	3,876	155	4,600	0	279		338	220	3,834	9,999 *(2)*
Natural gas	2,103	4,212	1,338	2,106	255	1,805	10,966	28,857	35,638	45,700	712	2,586	20,969	710	483	840	
Hard Coal	814	1,348	1,054	2,184		3,402	4,576	30,973	19,638	5,300			4,875		21,167	437	
Lignite			7,309					21,248							7,000		
Other fossils *(1)*					1,556	1,956					0					60	
Nuclear		5,930	4,290			2,860	60,590	12,068	9,401				515			9,568	3,155
Municipal Solid Waste				279	23	516		1,663	806		15		684	20	34	486	
Biomass	513	1,067	692	915	83	1,921	898	2,332	2,401	828	45	191	533	0	1,828	2,686	242
Biofuels				62	6	19		4,067	1,229						364		
Hydro	7,603	558	1,457		4	3,140	21,000	4,600	1,742	17,080	1,585	120	38	31,192	953	16,238	13,201
Pumped hydro	4,012					*(3)*	5,558	6,557	253	7,586		950		*(3)*	166	*(3)*	2,290
Offshore Wind		713		1,272		33		2,266	3,832				353			210	
Onshore Wind	2,411	1,517	283	3,625	303	972	10,293	41,652	7,798	8,958	68	424	3,074	874	5,100	5,825	60
Solar	929	3,228	2,083	608			6,548	39,698	9,082	18,910		58	1,400		21	120	1,394

Notes

(1) Other fossils includes peat and shale
(2) Oil capacity is increased in some countries to ensure demand can always be covered (e.g. Switzerland)
(3) For the Nordics, pumped hydro plants are included in the reservoir plants

Sources:
ENTSO-E (2016). Transparency Platform.
Energinet.dk (2016). Analyseforudsætninger 2016
The Wind Power (2016). Wind Energy Market intelligence.
IEA PVPS (2016). Trends 2016 in Photovoltaics application.
Different country sources and TSO reports

4.2 Fuel and CO_2 Prices

The fuel price assumptions for the analysis are based on the progressive convergence of forward prices in the short term and IEA World Energy Outlook 2016 [29] price levels in the long term. The prices from WEO16 are not directly used, but their development with respect to historical prices is used and applied to updated historical figures.

For the years up to 2020, the prices for coal, crude oil, and natural gas follow the forwards and futures market. Between 2020 and 2030, a gradual convergence to IEA price levels takes place.

From 2030 to 2040, price development follows IEA's projections, while the same slope is assumed after 2040.

The scenario chosen from the *IEA World Energy Outlook 2016* is the 450 ppm scenario. Among the reasons for choosing this price scenario are:

- IEA's historical underestimation of technological progress. Choosing their main scenario, the New Policies scenario, will likely lead to the underestimation of cost competitiveness of renewable energy (RE) technologies, and therefore estimating fuel prices in the high range.
- COP21. With the climate agreement in Paris, choosing the New Policies scenario might lead to an overestimation of fossil fuel demand and related prices.

Price development until 2030 is displayed in Figure 19.

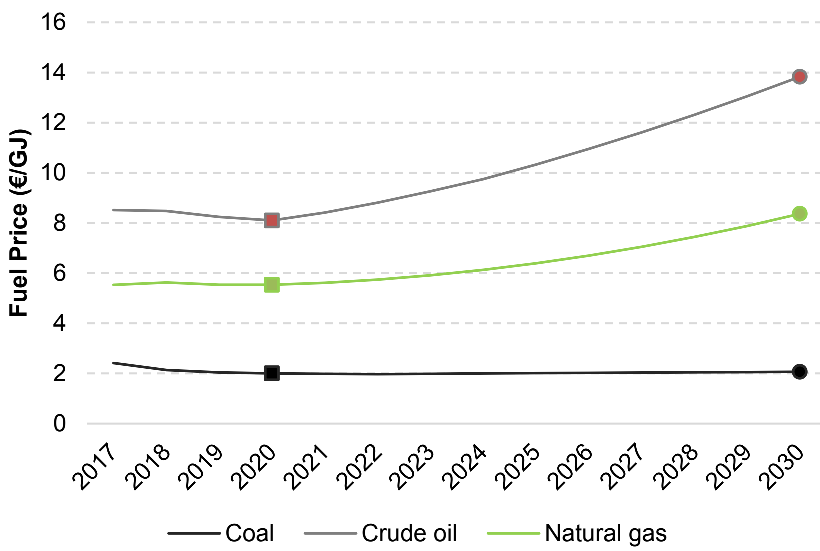


Figure 19. Fuel price projections assumed in the simulations

Europe has set an ambitious target of greenhouse gas emission reduction in the energy sector. The power sector is expected to carry the greatest share of the burden, with a reduction of CO_2 emissions greater than 50%. The development of the CO_2 quota prices largely depends on which other instruments are used to achieve the desired reduction. In many countries today, active efforts to increase energy efficiency and support schemes for renewable energy technologies are in place. In this study, it is estimated that this will not change significantly by 2030, and CO_2 reduction would have to be achieved through a combination of instruments; this means lower CO_2 prices compared to a case where emission reduction would be achieved through the CO_2 quota market alone.

The EU's Impact Assessment for EU climate and energy policy from 2020 to 2030 presented different scenarios for development of the energy system by 2030. In a scenario where climate objectives are achieved through a combination of targets for CO_2, renewable energy, and energy efficiency, CO_2 prices increased to 11 €/ton in 2030. Against this background, this analysis assumes a CO_2 price of 15 €/ton in 2030. Similarly, the price for CO_2 in the short term is based on forwards/futures contracts, corresponding to a level of 5.5 €/ton in 2020.

As an exception, the United Kingdom carbon price is assumed higher. It is based on best estimates for the development of the United Kingdom carbon price floor, which is currently fixed at 18 £/tCO_2 in addition to the EU ETS quota price. This level has been maintained constant until 2030.

4.3 Technology Cost

The main source of technical and economic data for new plants in the electricity and district heating sectors is the technology catalogue from the Danish Energy Agency [30], which contains projections until 2050.

In 2016 and 2017, several international tenders for wind and solar power resulted in lower-than-expected feed-in tariffs or premiums for the winning bids. As a result, the technology costs for offshore wind and solar power have been extrapolated and updated based on analyses of the recent tenders. The investment costs of new VRES installations, compared to the latest version of the technology catalogue[11], are shown in Figure 20.

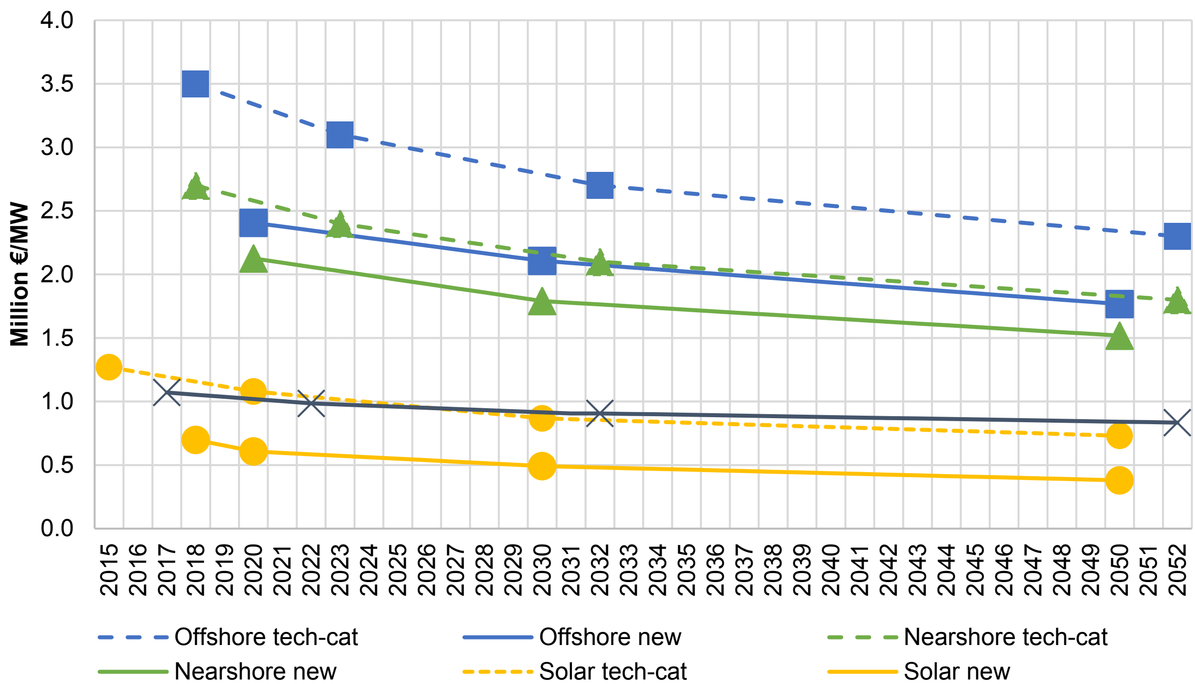


Figure 20. Technology cost of VRES. New projections based on latest tender results compared to technology catalogue (tech-cat).

[11] The *tech-cat* values in the figure refer to the technology catalogue as of the beginning of 2017. After the preparation of this report, the technology catalogue has been updated (June 2017) regarding investment cost for offshore wind.
The value of the latest catalogue version is almost perfectly aligned to the one considered in this study and shown in the figure.

4.3.1 Cost of Wind Power

The cost of land-based wind power depends on the chosen technology design and site-specific conditions, such as wind turbulence, grid connection, and road access. For this study, differences in investment and fixed operation and maintenance (O&M) costs due to varying hub height and rotor diameter are taken into account, while site-specific differences are not evaluated. Grid connection costs are part of the investment cost considered for single turbines. Thus, lower total installed capacity also implies some savings on grid connections. However, the differences in cost-per-megawatt installation capacity for different turbine types have only been evaluated as total sum and not for individual components.

Cost estimates for land-based wind power across Europe are all based on the *Technology Catalogue* by the Danish Energy Agency and the Danish transmission system operator Energinet.dk [30].

The technology catalogue does not include information on the economics of different wind turbine designs. Therefore, the basic projection for the cost for land-based wind power has been expanded to include differences depending on the hub height and specific power.

Investment cost as function of rotor diameter

The cost of achieving lower specific power will depend on the approach. For simplicity, the approach assumed here applies a larger rotor to the same generator rating. Another approach could be to reduce generator rating and deploy more turbines in order to achieve the same annual generation as higher specific power machines. If the cost and availability of land is not a strong restriction, this latter approach could prove to be less costly, thereby improving the economics for a system based on low specific power.

The National Renewable Energy Laboratory (NREL) has estimated the investment cost for varying rotor sizes at equal hub height and capacity rating based on data for the U.S. market and a bottom-up model that estimates the cost of turbines with different configurations [31], [32]. The estimates are made for a 2-MW turbine with specific power ratings from 200 W/m^2 to 325 W/m^2, with a corresponding diameter ranging from 113 m to 89 m. NREL estimates investment cost ranging from 1.39 million €/MW to 1.57 million €/MW (Figure 21).

The investment cost, dependant on the rotor diameter, has been approximated by a second order polynomial, following an approach used in [33]. As the baseline turbine in the Danish technology catalogue has a capacity rating of 3.5 MW, the diameters required to reach the specific power applied in the scenarios (325, 250, and 175, respectively) are considerably higher, and the extrapolation of NREL estimates is subject to uncertainty. The applied polynomial function takes into account the likely increasing cost for marginal expansion of the rotor with increasing diameter, compared to linear extrapolation. The approach has large uncertainties, primarily due to the fact that the values considered lie well outside the range of data in the NREL study. This results in a conservative estimate for the cost of larger rotors, which is more likely to over- than to underestimate cost increments. Additionally, future higher turbine ratings[12] can lead to lower additional costs per megawatt than estimated here.

[12] The Danish Technology Catalogue estimates a capacity rating of 5 MW for land-based turbines by 2050 [30].

The absolute specific costs estimated by NREL are higher than those in the Danish technology catalogue, partly due to the lower capacity rating and associated turbine economies of scale at higher capacity ratings. Therefore, the relative ratio between turbines with different specific powers at the same capacity rating has been applied to the Danish baseline. The resulting relative cost increase for decreasing specific power from 325 W/m^2 to 250 W/m^2 is 10%; there is an additional 16% for reducing to 175 W/m^2. For comparison, IRENA [34] estimates a specific cost increase of 20% for going from "old" (diameter <95 m) to "new" (diameter >95 m) turbines, based on Bloomberg New Energy Finance's Wind Turbine Price Index (BNEF WTPI).

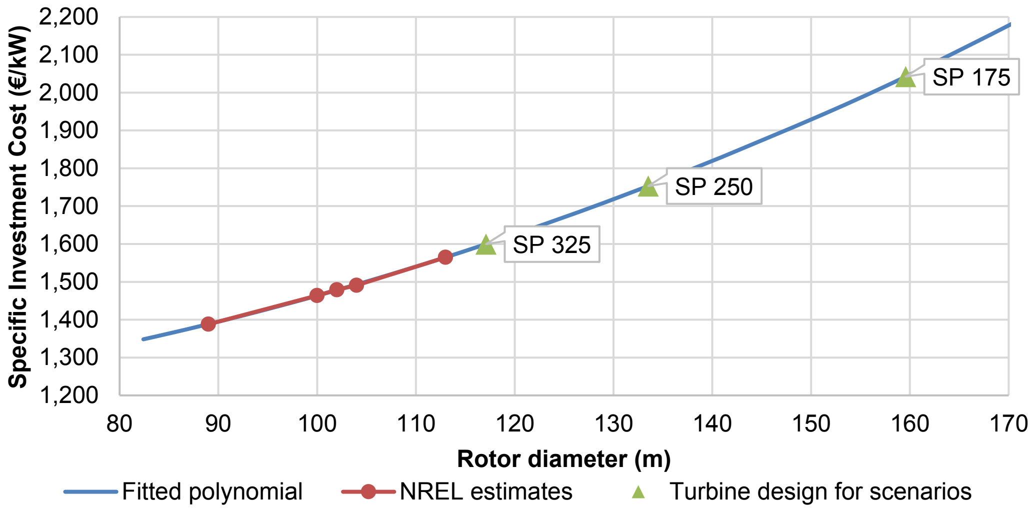


Figure 21. Estimated investment cost as function of diameter. Illustration based on data from [31] and own calculations. Applied exchange rate USD to EUR equal to average 2015 rate of 0.90. Diameters for turbine design applied in scenarios correspond to 2020 values.

Investment cost as function of hub height

Estimates for the cost to increase hub heights are based on data for German land-based turbines from a 2016 cost survey [35], and extrapolation is based on a second order polynomial. The influence of the hub height is applied to the Danish baseline using the relative differences, showing a cost increase of 16% from 100 m to 125 m and an additional 20% going from 125 m to 150 m in hub height. For comparison, Engström et al. estimated 12% and 5%, respectively [36]. As for decreasing specific power, the estimates on increased cost for increased hub heights are considered a conservative estimate, more likely to over- than underestimate the additional cost of higher hub heights. Similar to additional cost for larger rotors, additional cost for higher towers could be reduced by higher turbine capacity ratings.

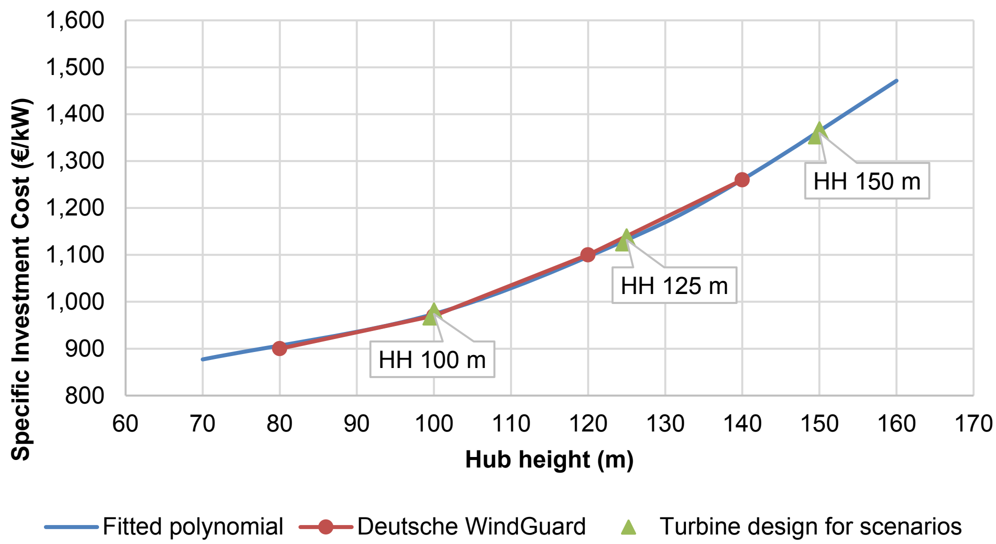


Figure 22. Estimated investment cost as function of hub height. Illustration based on data from [35] and own calculations.

Applied cost for land-based wind turbines

The cost for land-based wind turbines in the applied configuration, based on the baseline in [30] and the above explained dependence on rotor diameter and hub height, is shown on Figure 23 for 2020. The specific cost of turbines in the Likely and Ambitious scenarios increase by 28% and 82% compared to the BaU by 2030. Cost reductions between 2020 and 2030 are around 13% based on [30] (see Appendix 1). There are no publicly available data to analyze the effect of increasing hub heights and rotor diameters on specific fixed operation and maintenance cost. Therefore, the same adjustment factor as for investment cost has been applied. Although not investigated in detail, it seems reasonable that more advanced technology (larger rotors/higher towers) somewhat increases maintenance cost per megawatt. However, the share of maintenance cost related to generator and nacelle will be largely unaffected by larger rotors, and thus the estimates applied here are likely to slightly overestimate increases in maintenance costs. Variable operation and maintenance costs are unchanged compared to the reference [30].

The estimation of the effects of hub height and rotor diameter on specific investment cost and fixed operation and maintenance cost is subject to uncertainty, especially due to the limited data available and because the applied turbines in the Likely and Ambitious scenarios are not widely deployed in Europe today. The costs are therefore further analyzed in terms of maximum threshold cost, before possible benefits of system savings would be offset by the increased cost (see Section 6.3).

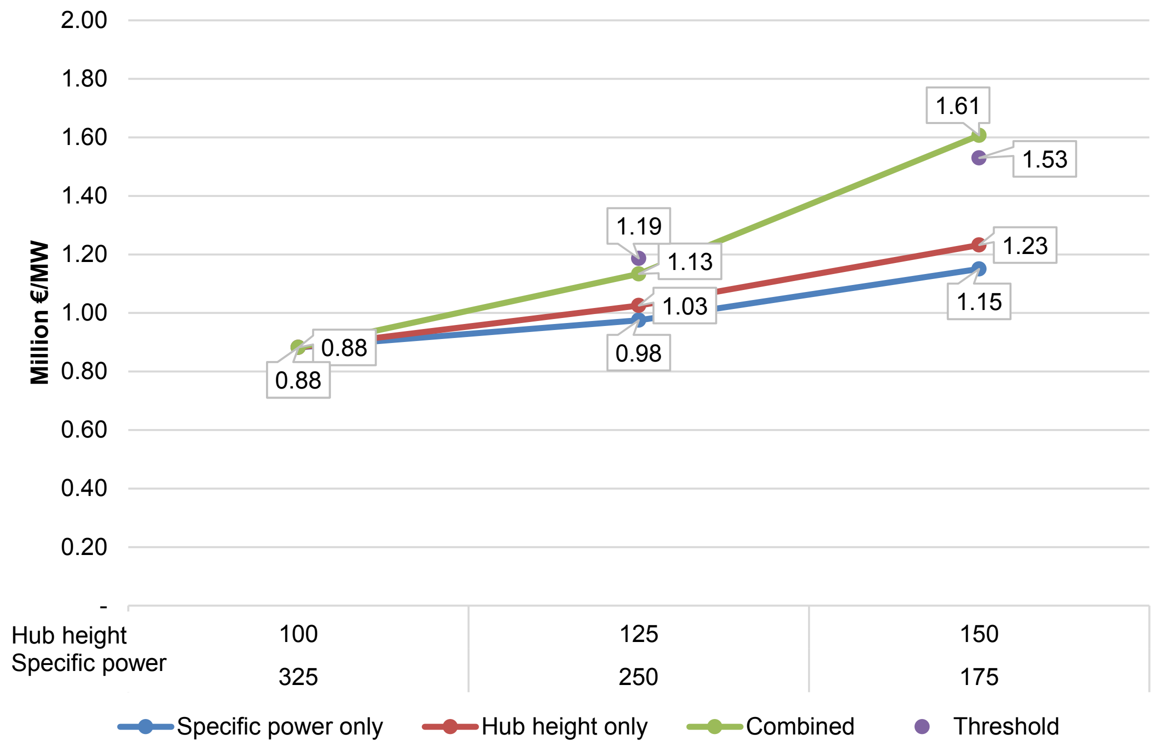


Figure 23. Specific investment cost for land-based wind turbines in 2030, dependent on hub height and specific power. Blue lines show cost development if only specific power is changed, red lines show development if only hub height is changed, and green lines show development of investment cost if both hub height and specific power are changed, corresponding to the Likely and Ambitious scenarios. See Section 6.3 for details on calculation of "threshold values". Source: Own calculations based on [30], [31], and [35].

4.4 RE in Europe

The development of the installed renewable capacity in Europe, particularly low OPEX and variable renewable energy technologies like wind and solar, has a large effect on the outcome of the market. Assumptions for future development are based, in part, on ENTSO-E's Scenario Outlook and Adequacy Forecast (SOAF) [37], with national development until 2025 and linear extrapolation to 2030, which reflects the assumption that development continues based primarily on national support.

The RE advancement in Denmark, Germany, and the United Kingdom are based on national sources. For the United Kingdom, wind and solar are based on National Grid FES 2016 [38], scenario *Slow progression*, while biomass is elaborated from the *Updated Energy and Emission Projections (UEP)* of DECC [39]. Renewables in Germany are taken from the Network development plan (*Netzentwicklungsplan - NEP*) 2017, Scenario B [40]. For Denmark, the exogenous capacity for wind and solar is based on an elaboration of *Energinet.dk's Analyseforudsætninger 2016* [41].

In addition to the described development, the model is allowed to invest in additional RE capacity, including wind and solar, based on their market competitiveness and a small level of national subsidy, up to maximum national potentials.

The level of solar and wind generation is estimated as described above for the BaU scenario. These levels—in gigawatt-hour energy terms—are then fixed and kept constant across all of the technology scenarios, ensuring equal amounts of wind and solar (before curtailment) in all scenarios modeled.

4.5 Transmission System Expansion

The expansion of net transfer capacities is based on the 10-year network development plan (TYNDP) 2016 from ENTSO-E [42]. Among the developments described, all medium-term and long-term projects have been represented, leading to the development shown in Figure 24, where the transmission system in 2016 (left) and its expansion in the period 2016-2030 (right) is shown.

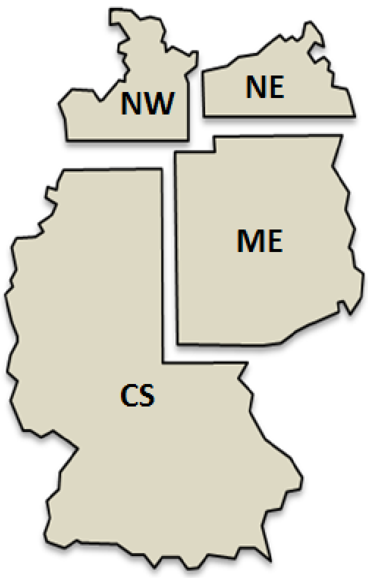


Figure 25. Subdivision of Germany in regions in the model (left) and main transmission bottlenecks in the German grid (right)

In Germany, the current EPEX day-ahead market setup consists of a single price zone (together with Austria). In reality, internal congestions in the German grid set limitations on the possible flows across the country, particularly in the north-south corridor. This is managed by redispatch measures performed by the TSOs after the market clearing to make sure the system operates within its limits. For this reason, Germany is modeled with four price areas, chosen to reflect the main bottlenecks in the system, which are located mainly between northwest and south, as well as between east and south. This leads to a better representation of the actual system operation and associated cost, compared to modeling Germany as one zone. At the same time, the modeled market prices do not reflect the current market setup.

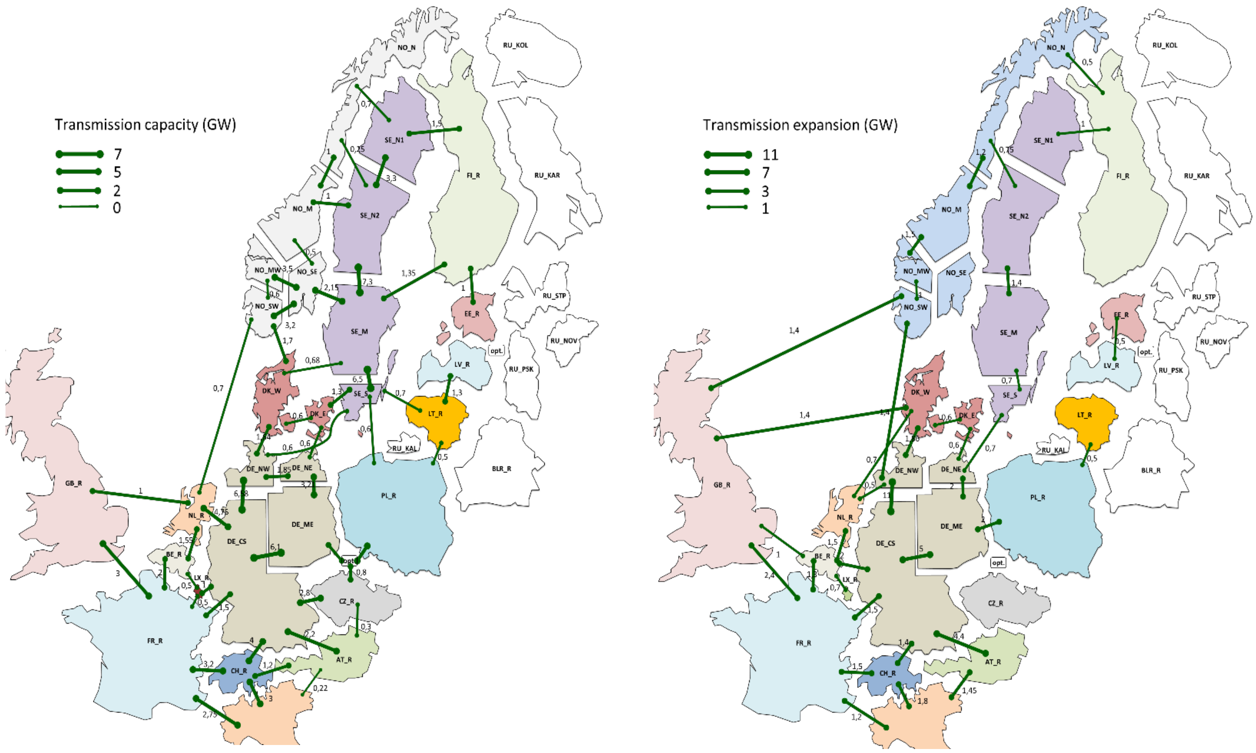


Figure 24. Transmission capacity between regions in 2016 (left) and additional expansion in the period 2016-2030 (right) based on TYNDP16

Within Germany, internal expansions from the national TSOs' grid development plan were directly implemented until 2020, while the most controversial expansion corridors were assumed to be delayed to 2025 compared to initial plans. This is in line with current official statements from the TSOs involved.

The specific assumptions are summarized in Table 3. The largest increase in the transmission to the DE-CS region is between 2020 and 2025, with an increase of 3 GW from DE-ME and 6 GW from DE-NW, where most of the wind power is installed.

Table 3. NTC in the German North-South Corridor (GW)

From Region	To Region	2015	2020	2025	2030
Middle East Germany (DE-ME)	Central-South Germany (DE-CS)	6.1	6.1	9.1	11.1
North-West Germany (DE-NW)	Central-South Germany (DE-CS)	6.6	7.6	13.6	17.6

4.6 Investment Setup

Besides the technology costs, some restrictions are applied to the development of specific energy sources and technologies. Limitations to conventional generation capacities, namely fossil fuel and nuclear plants, are based on a bottom-up approach that takes into account government plans in each respective country, including the official decommissioning of thermal and nuclear power plants. Inputs and outputs are summarized in Table 4. For investment optimization, a general weighted-average cost of capital of 5% and an economic lifetime of 20 years is applied.

The main assumptions are the following:

- The decommissioning of existing power plants is allowed in the model after 2020, meaning that 2025 is the first year in which existing capacity can be decommissioned. A plant is decommissioned by the model if the revenues from the market in the modeled year are lower than the fixed and variable costs, the fuel cost, and the CO_2 cost for operating the plant[13].
- No endogenous investments in Germany for nuclear are allowed, and decommissioning of the current plants takes place following the phase-out plan of the country
- Exogenous development of nuclear for other countries such as Finland, Sweden, France, and Switzerland, based on the government plans and expectations
- No new investments in coal are allowed in Europe, except for Poland, following a statement made by Eurelectric in 2017 [43]
- No carbon capture and storage technologies are available, due to the fact that the technology is not projected to be cost-effective and widely deployed by 2030.

Table 4. What is an Input and What is a Result of the Scenarios?

Input	Scenario Result
Existing generation capacity	Available generation capacity after economic decommissioning. New generation capacity according to economic optimization.
Minimum RE deployment	Total RE deployment, including beneficial investments, according to economic optimization on top of minimum RE deployment (total deployment of wind and solar power is determined in BaU scenario, other scenarios use the same deployment (input)).
Existing and future transmission capacities	Usage of transmission capacity. No model investments in transmission capacity.
Fuel- and CO_2 prices RE subsidies	Power prices
Demand projections	Demand is met, unless power prices would rise above 3,000 €/MWh. Power demand for district heating generation is determined endogenously.

[13] The effect of the decommissioning of excess capacity in the model is reflected on the power prices, which tend to increase because of the lower amount of capacity available (especially low-variable cost conventional generation).

5 Limitations of the Analysis

This chapter lists the potential limitations of the current analysis both in terms of specific data and modeling assumptions.

5.1 Market Setup in Germany

Two assumptions in the German market modeling framework deserve to be discussed: the number of market zones and the portion of energy traded in the day-ahead market.

In the analysis, Germany has been modeled with different price zones. While splitting Germany into different market zones allows for a consideration of internal bottlenecks and the effect of alleviating congestion, it has the downside of creating fictional price zones, which do not reflect the potential EPEX[14] market outcome. This affects the resultant value of wind and enables one to draw socio-economic conclusions, but the results are weaker from an investor perspective because of the mismatch with the current EPEX market setup. The difference compared to a single market zone is, however, reduced over time thanks to the progressive alleviation of bottlenecks. It is also possible that greater geographic price differentiation will be introduced in the EPEX over time.

As for the market setup, the model simulates the mechanism of the day-ahead market, assuming all of the generation fleet participates in it. In reality, the share of the total volume traded in EPEX is lower because several producers, especially large conventional plants, deliver their energy through bilateral contracts. The lower day-ahead market share results in a more pronounced merit order effect, due to a larger share of non-dispatchable renewable plants. It must be noted that the share of total energy traded in the day-ahead market is currently increasing in EPEX, and is already higher for other European spot markets such as Nord Pool[15].

5.2 Uncertainty in Wind Penetration Projections

The projections of wind deployment in every modeled country, which are based on best available information, are subject to a large degree of uncertainty. Technological and cost evolution, as well as political decisions, will influence the path of wind deployment in Europe until 2030.

In Germany, the level of ambition and future deployment of wind power will influence the European picture in terms of prices and market value of wind, due to the large land-based wind buildout in the country. The assumptions for Germany are based on the NEP 2017 Scenario B, which projects a land-based wind capacity in 2030 equal to 58.5 GW, with an annual generation of 125.3 TWh [40]. However, based on both the current plan for expansion set by the EEG17 and the expected expansion at the federal level, this level might be underestimating the future development of land-based wind energy in the country. A larger penetration of wind would entail a larger price pressure in the market with consequent further reduction in the market value of wind.

5.3 Turbine Cost

The cost of the different wind turbine designs is difficult to extract, given the lack of publicly available data. The figures used are based on extrapolations from bottom-up models and other

[14] EPEX SPOT is the exchange for the power spot markets of Germany, France, Austria, and Switzerland.
[15] As a comparison, the share of energy traded in the day-ahead market in 2013 was 85% for Nord Pool and 39% for EPEX [48].

estimates. Moreover, the cost for the single design parameter variation, such as hub height and specific power, is hard to isolate from the total turbine cost. Equally difficult is assessing the degree to which historical or present cost differences among turbine technologies may change over time as wind technology advances. Therefore, the estimates used in this analysis are subject to large uncertainty.

Moreover, there are different ways to achieve lower specific powers on a turbine. The cost estimation considers increasing the length of the blades given the same installed capacity. However, the same specific power could be achieved by reducing the generator size with the same blade length, and this measure possibly results in lower CAPEX cost than the ones considered.

5.4 Dispatch Model Limitations

The main limitations of the Balmorel model are the following:

- It assumes perfect competition and no presence of market power, while in reality the power and heat sector are still subject to market failures.
- Balmorel is a deterministic model, applying perfect foresight and optimization based on the total amount of information available. This can lead to optimal solutions, which in reality would not practically hold due to the uncertainty in key parameters such as hydro inflows, wind speeds, irradiation, and demand level.
- Uncertainty of input data: due to the very large amount of data input, many of which represent projections of costs and performance in the future, the results from the model are largely dependent on the underlying data. This limit is not specific to Balmorel, but in general related to modeling simulations.
- The level of detail of input data is aggregated in different dimensions, (e.g. aggregated generation fleet, no detailed fluctuation of fuel prices (only seasonality of gas price)).
- Short sight in investment optimization, when optimizing investments, the model considers only a single year. If the plant pays back the annuity of the total investment in that single year, the plant is then invested in. As a consequence, the condition of the future system is not taken into account.
- No representation of internal grid and power flows: each region in the model is considered a copper plate and no detailed representation of the internal grid is present in the model. Moreover, the resultant inter-regional flows from the market clearing have no limit beside the maximum transmission capacity. There is no certainty that the resultant flow would be technically feasible from a grid perspective.

5.5 Wind Modeling

Wind power generation has been modeled and assessed in detail in the current study. However, the modeling has some limitations owing to, amongst others, the aggregated nature of the representation of wind power within regions. Some limitations are listed in the following.

5.5.1 Technology Considerations

The scenario setup in the current analysis is illustrative and assumes the same technology is installed in every modeled region, regardless of the wind resource quality. While this helps to isolate the technological effects and better understand the results, this might not be realistic in two ways.

There are some limitations to installing low specific power turbines in higher wind sites due to turbulence effects and high loads. Moreover, the optimal choice of technology and turbine model is site-specific, both in terms of hub height and specific power. For example, sites with higher shear factor could see a higher benefit by increasing hub height, despite the cost, or turbines with higher specific power might be more valuable in sites with better resource quality and low price pressure in the market. However, as mentioned previously, new models with low specific power started to appear for higher IEC classes, and there is evidence of installations of LWST in sites with high average wind speeds, especially in the United States.

5.5.2 Inter-annual Wind Variations

The analysis, and more generally the Balmorel model setup, is meant to simulate and describe a normal wind year, (i.e., a year with average wind resource). In reality, wind years can largely differ from a normal one. In fact, according to [39], the wind index reported for Denmark in the last 10 years has varied in the range of 0.9-1.13 (coefficient 1 representing a “normal” wind year). This variation is not simulated in the present study.

The effect of inter-annual variations of the wind resource results would be a higher or lower wind generation, and thus a different impact on the merit-order. This would result in a variation of the market value of wind, which is not simulated in this study.

Another potential benefit of advanced wind technology relates to the potential benefit of reducing the inter-annual variations. Since the production at lower wind speeds is increased, a low wind year would have a reduced impact on the generation, compared to less advanced technology. This effect and its potential benefit has not been explored in this analysis.

5.5.3 Extrapolation of Wind at Higher Heights

The extrapolation of wind speeds at higher hub heights is done using the power law. This method is simplified and is greatly dependent on the choice of the shear factor, which can be very different for various sites inside a certain modeled region. Therefore, depending on the sites, the energy gained from increasing hub height can vary widely, as does the value of increasing height.

The shear factors considered in the analysis are average values for the region modeled, and therefore, neglect any specific site conditions and considerations. The values are in the range of 0.14-0.22 for land-based wind locations and 0.08-0.14 for offshore locations.

6 Results

The overall system results and economic evaluation of scenarios are based on the entire modeled area. Detailed results for the market value, power price duration curve, and curtailment vary by region. This part of the results is presented with a focus on Germany, due to level of detail in the modeling, the importance of Germany in the European energy context, and Germany's ambitious goals for land-based wind development.

6.1 System Results in the BaU Scenario

The status of the power system in the BaU scenario is described in terms of annual generation, wind penetration, and average wholesale prices.

6.1.1 Annual generation

Figure 26 shows the resultant development of generation in the entire modeled system for the BaU scenario from 2015 to 2030. The trend is an increased RES-E generation at the expense of the conventional generators (both nuclear and fossil fuels), which are decommissioned.

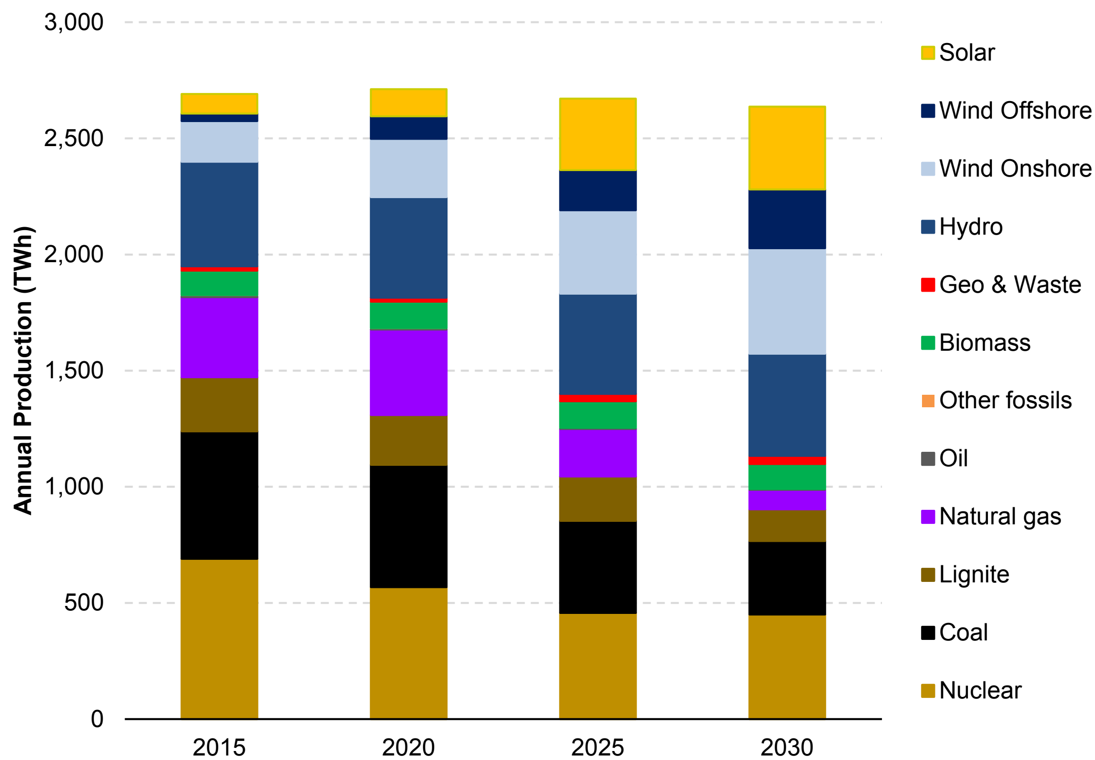


Figure 26. Evolution of annual generation in the modeled region (Europe)[16]

The effect of nuclear decommissioning in Germany and the lower pace of reinvestments in other countries reduces the share of nuclear power from 26% to 17%. Fossil fuels halve their

[16] Countries included: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Sweden, Switzerland, and the United Kingdom (excluding Northern Ireland).

contribution, from 42% to 20%. Solar photovoltaics and wind power that see the largest increase, with their share of total generation increasing from 11% in 2015 to 40% in 2030.

In Germany, VRES provides almost 50% of the country's generation in 2030, with the rest provided mainly by coal and lignite since nuclear is completely decommissioned by 2025.

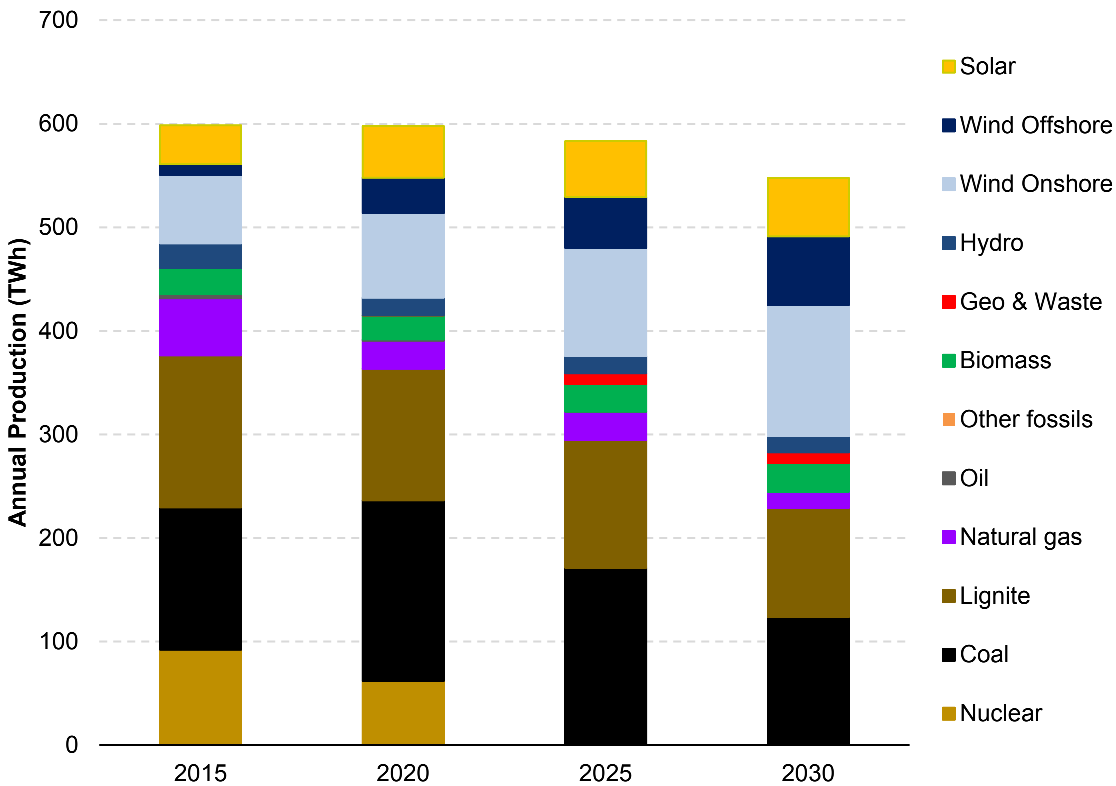


Figure 27. Evolution of annual electricity generation in Germany

6.1.2 Land-Based Wind Power Generation

The level of annual land-based wind power generation simulated for the BaU scenario, kept constant across all technology scenarios, is shown in Table 5. This is the combined result of the minimum level imposed and the investments based on market conditions.

Table 5. Annual Land-Based Wind Generation by Country and Year in Terawatt-hours. Last two columns indicate the land-based and total wind penetration with respect to power demand in 2030.

	2015 (TWh)	2020 (TWh)	2025 (TWh)	2030 (TWh)	Land-based Penetration in 2030 (%)	Total Wind Penetration in 2030 (incl. offshore) (%)
Germany	66.2	81.7	104.6	126.7	***25***	***38***
UK	17.7	30.0	52.3	75.8	***23***	***50***
France	19.9	26.7	49.9	75.3	***17***	***25***
Italy	17.1	24.1	26.4	30.4	***9***	***12***
Sweden	14.3	19.4	21.5	23.7	***18***	***18***
Poland	10.9	17.1	19.5	21.9	***13***	***17***
Netherlands	6.2	11.9	21.3	26.6	***23***	***38***
Denmark	8.4	12.1	16.2	20.0	***52***	***82***
Norway	2.1	4.1	17.3	16.9	***12***	***13***
Austria	5.1	8.1	8.2	8.2	***13***	***12***
Belgium	2.8	4.6	7.6	10.6	***12***	***24***
Finland	2.2	5.0	7.7	10.4	***12***	***15***
Estonia	0.5	1.7	1.8	1.9	***20***	***20***
Lithuania	0.9	1.4	1.7	1.8	***16***	***28***
Latvia	0.1	1.5	1.8	2.1	***27***	***48***
Czech Republic	0.5	1.0	1.3	1.6	***2***	***2***
Switzerland	0.1	0.2	0.3	0.4	***1***	***1***

6.1.3 Average Wholesale Electricity Price

The "heat map" in Figure 28 shows the modeled average wholesale electricity price and the annual net flow across regions in the BaU scenario in 2030.

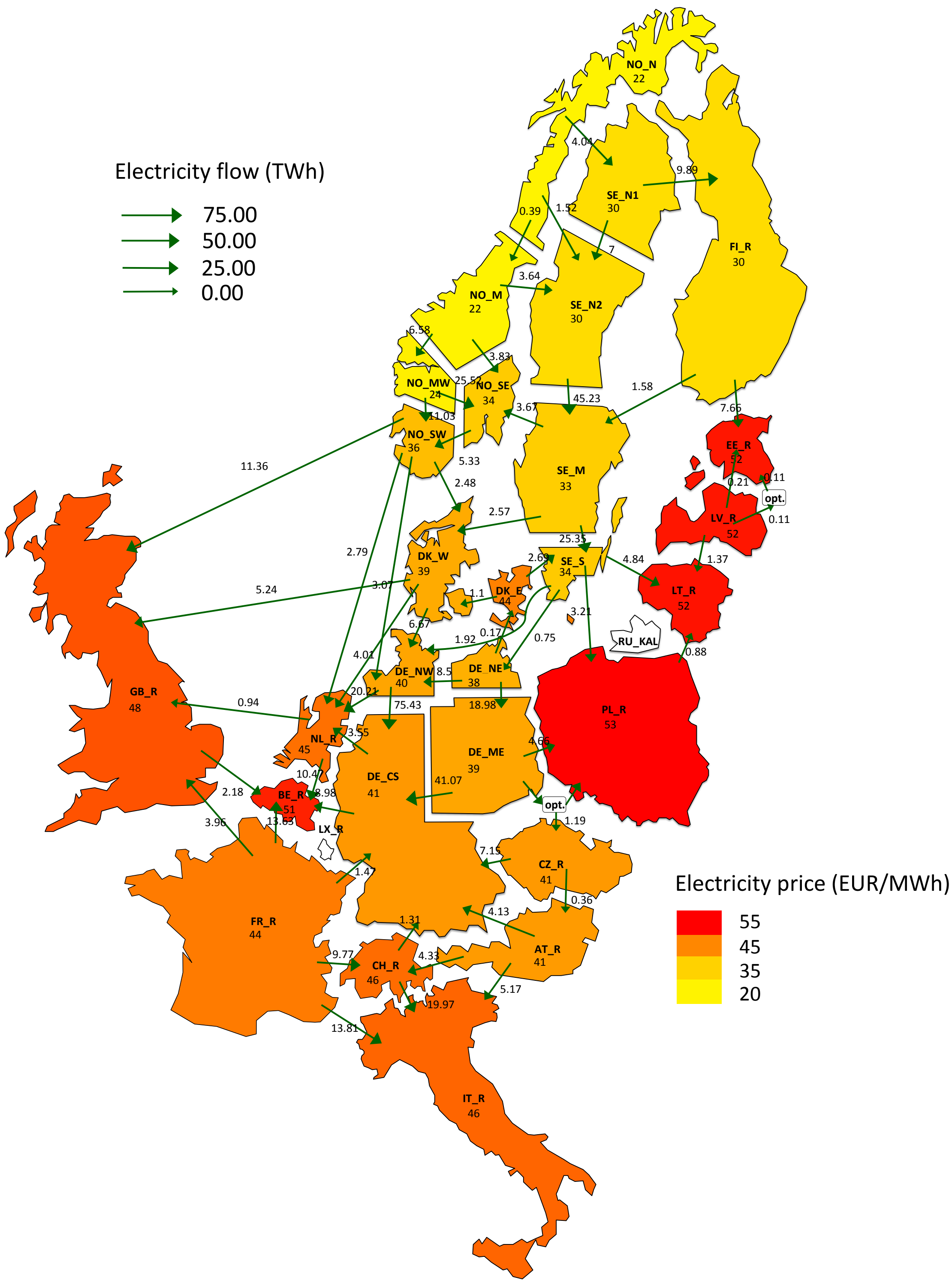


Figure 28. Average wholesale electricity market price by region in the BaU scenario in 2030

6.2 The Effect of Technology Advancement on the System

6.2.1 Land-based Wind: Installed capacity and duration curves

In the different technological scenarios, specific power and hub height changes affect the production pattern and the capacity factors (full-load hours) of land-based wind. Since the land-based wind penetration levels by country are fixed across scenarios and the total wind production is the same, changes in the full-load hours affect the required wind capacity in each scenario.

Table 6 shows the installed capacity of land-based wind power in Germany in the different scenarios. While historical capacity and decommissioning pace[17] is the same, scenarios with advanced technology feature lower capacity for new installations. The capacity needed in the Ambitious scenario is around half of the capacity in the BaU scenario.

Table 6. Installed Land-based Wind Capacity by Scenario, Historical and New Installations

		2015	2020	2025	2030
Historical wind capacity (GW)		42	38	26	17
	Ambitious	-	6	18	28
New wind capacity (GW)	Likely	-	8	25	39
	BaU	-	11	35	55

Given the difference in installed capacities, it is interesting to look at the duration curve of land-based wind power[18] and see how wind production is distributed during the year. The shape of the duration curve depends only on the technology characteristics, as the wind conditions are the same across scenarios in this study.

Figure 29 shows the evolution of the duration curve for land-based wind in Germany in the three scenarios. Higher capacity factors enable wind to produce the same energy with a lower capacity, therefore reducing the peak of wind feed-in. When reducing specific power and increasing hub height, the production in the 2,000 hours with the highest wind is reduced; in turn, there is a generation increase in the remaining hours, corresponding to lower wind periods. Reducing the peak of the wind in-feed has potential benefits in the integration of wind power and positive system impacts, both in terms of reduced market impact and lower need for integration measures. For example, there is a reduction in the need for costly transmission network expansion, for which wind power variability is becoming a deciding factor in many countries.

Because the historical fleet is modeled in the simulations, the difference in the feed-in across the scenarios analyzed is increasing over time with the retirement of older turbines. Therefore, the new installations have a larger effect in the long term.

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[17] Decommissioning pace is based on commissioning year in the different countries and a flat assumption on the lifetime of the turbines. The higher revenues arising from more system-friendly wind will also benefit existing turbines and the likelihood of lifetime extensions will increase.

[18] The duration curve shows the number of hours over the year (x-axis) when the feed-in from land-based wind turbines to the grid was above a certain power (y-axis). The area under the curve represents the total annual electricity production from land-based wind.

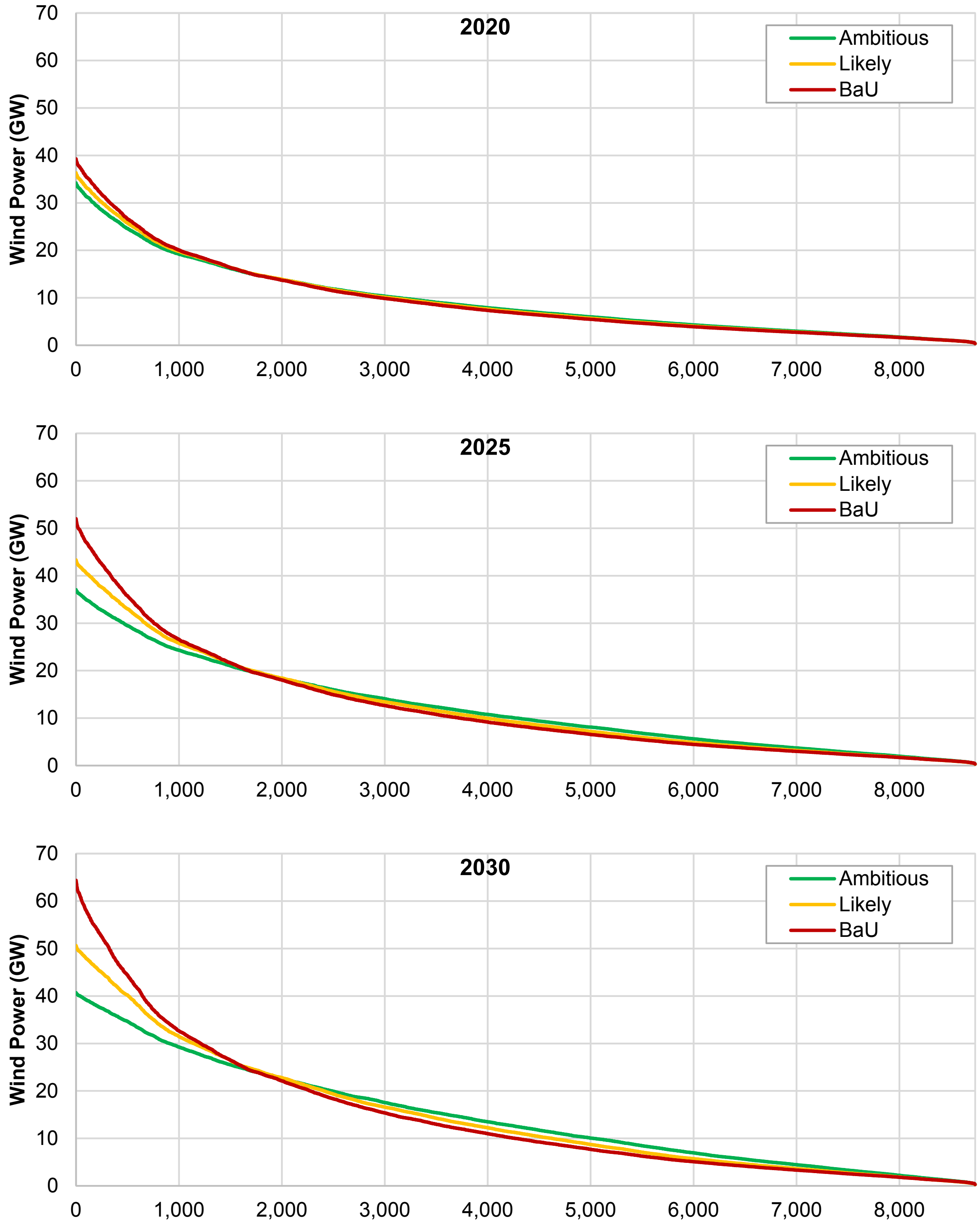

Figure 29. Land-based wind duration curve for Germany across the three scenarios in 2020 (top), 2025 (middle), and 2030 (bottom)

6.2.2 Seasonal Variation

When looking at the monthly distribution of wind production for the Ambitious and the BaU scenario in Figure 30, one can note that utilizing advanced wind designs reduces the seasonal variation of wind by providing more generation in summer and less in winter. Turbines in the

Ambitious scenario produce up to 120% in summer months and 82% in winter months compared to BaU wind generation. This effect is positive for the energy system, because it reduces the variability of the resource across the year.

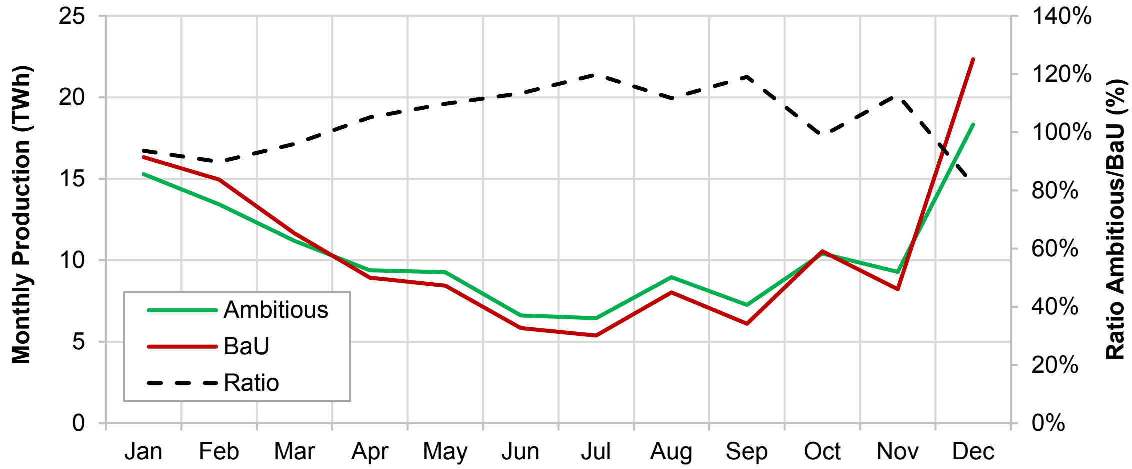

Figure 30. Monthly distribution of wind generation in Germany (2030) for the Ambitious and BaU (left axis) scenarios. The dotted line is the ratio between the two (right axis).

However, the combined utilization of solar PV and wind power has been depicted as a good VRES integration practice, since solar and wind production are more concentrated in summer and winter, respectively. In the simulation, the seasonal variation of the combined profile of solar and wind (both land-based and offshore) was still lower in the Ambitious scenario compared to BaU.

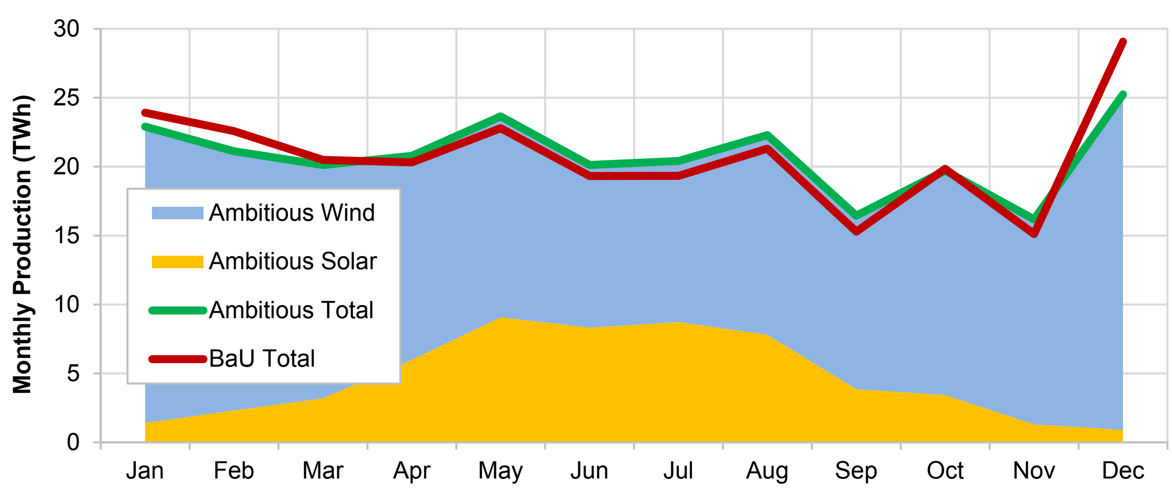

Figure 31. Seasonal variation of the combined wind and solar profile for the Ambitious and BaU scenarios, Germany 2030. Monthly solar and wind for the Ambitious scenario are shown as reference

The extent a system mostly based on advanced turbine design reduces the advantage of resource combination when planning a future energy system depends on the amount of solar in the system, which is a topic for further research.

6.2.3 Residual Load Duration Curve, Curtailment, and Capacity Credit

To visualize the positive effect of deploying advanced turbines on the system, residual load duration curves[19] can be used. An increasing share of wind power into the system can result in temporary situations of renewable energy surplus, which has to be addressed through dedicated integration measures to avoid the curtailment of production that cannot be accommodated in the power system.

The utilization of advanced turbine designs in terms of both specific power and hub height can serve the purpose by making the residual load easier to serve in three ways: increasing the room for baseload, reducing the surplus of renewable energy, and reducing the need for firm generation (lower peak of the residual load duration curve). The first two effects are clearly depicted in Figure 32, representing Germany in 2030. The curve is less steep in the hours with lower residual load and the hours with negative load are reduced from 151 in the BaU scenario to 39 in the Likely scenario and 2 in the Ambitious scenario.

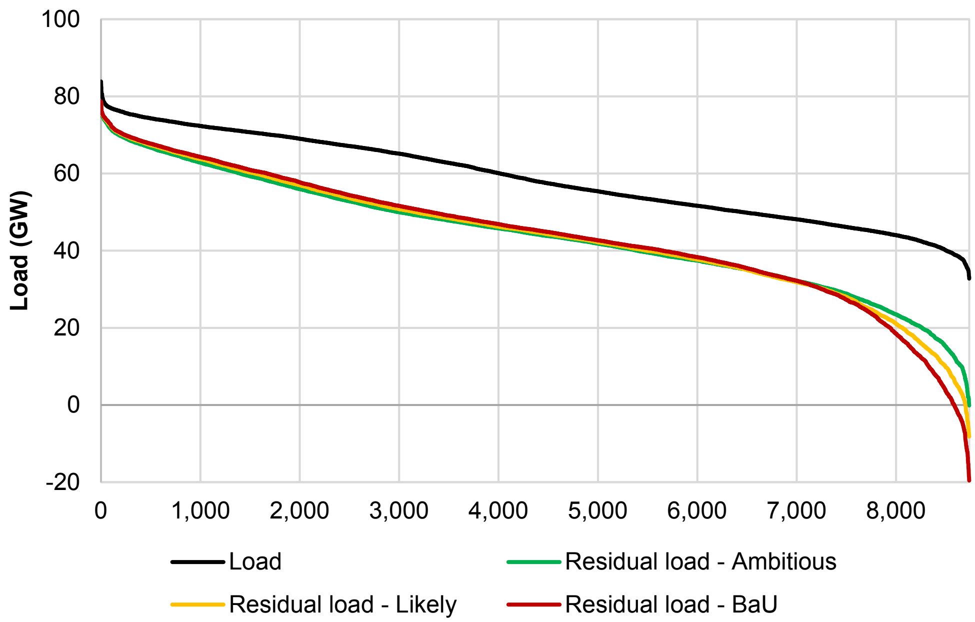

Figure 32. Load duration curve and residual load duration curve by scenario, Germany 2030

At the peak of the residual load duration curve, it is convenient to look at the capacity credit of wind power. Capacity credit can be calculated as the difference in the peak of the load and the peak of the residual load (peak reduction), divided by total wind installed capacity [44]. It represents the percentage of total wind power that can be considered as firm capacity, and thus contributing to capacity adequacy.

[19] The residual load duration curve is calculated by subtracting hourly wind generation from hourly demand data.

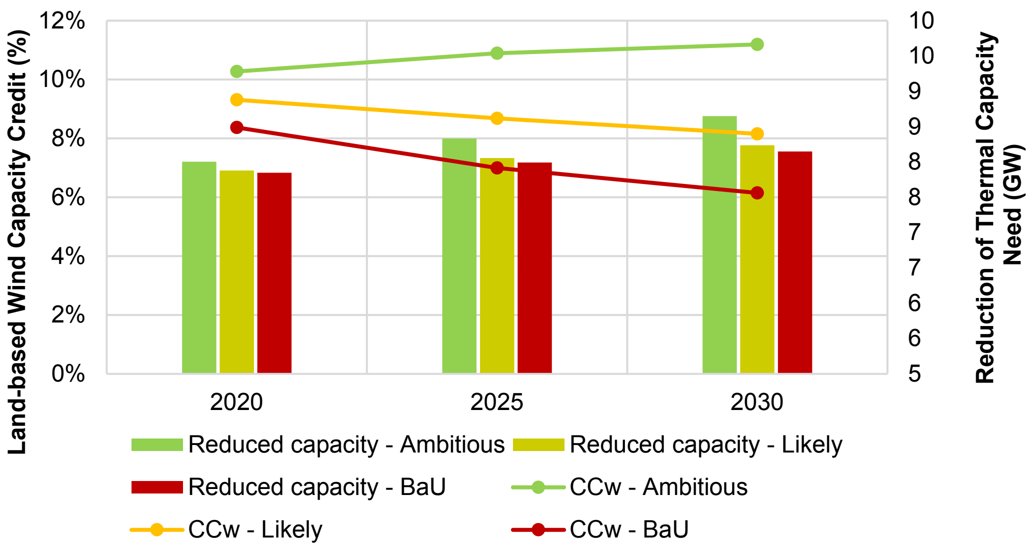

Figure 33. Capacity credit of land-based wind [CCw] (left axis) and reduction of the peak (right axis)

The resulting capacity credit (Figure 33) confirms results from previous studies, such as increased capacity factors and improved wind technology, leading to higher capacity credit across all wind penetration levels. In the extreme case of the Ambitious scenario, the capacity credit increases over time, regardless of the increment in installed capacity and wind penetration.

Alternatively, the peak reduction is around 8 GW in 2030, with a difference between scenarios of 100 MW from BaU to Likely and 410 MW from Likely to Ambitious. The minor value can be explained by the fact that the peak in the residual load duration curve is taking place during hours of low wind speed. Advanced technology increases production in intermediate wind conditions, with much less production in the low wind hours. As a consequence, the higher capacity credit of the advanced technology scenarios is mainly due to a lower installed capacity of wind power, which ensures a higher level of firm capacity in terms of percentage value.

It should be emphasized that this result can only be considered illustrative. Indeed, more precise metrics to assess the capacity value of wind in a system exist, which rely on probabilistic and more rigorous methodologies, such as considering a larger number of years for wind and demand profiles[20].

When looking at curtailment, the wind generation that needs to be curtailed in the system decreases as the wind surplus is reduced. Figure 34 shows the levels of total wind (land-based and offshore) curtailment in Germany across scenarios. The largest reduction of curtailment takes place going from the BaU to Likely scenario, 50% in 2025 and 36% in 2030. Going from Likely to Ambitious technology, the curtailment is reduced to a lower extent (around 30% additional reduction).

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[20] For example, see *"IEA Wind Task 25. Expert Group Report Recommended Practices 16 - Wind Integration Studies"*. Edited by H. Holttinen. 2013. Available at www.ieawind.org/task_25.

In percentage terms, the curtailment in 2030 is equal to 1% of the total wind generation in the BaU scenario, 0.6% in the Likely scenario, and 0.5% in the Ambitious scenario. These values reflect only the curtailment that is due to congestion at the transmission network level and disregards curtailment related to congestion at the distribution level. Therefore, curtailment levels are underestimated in regions with congestion in the distribution grid, which is the reason for higher curtailment rates in regions like northern Germany [45].

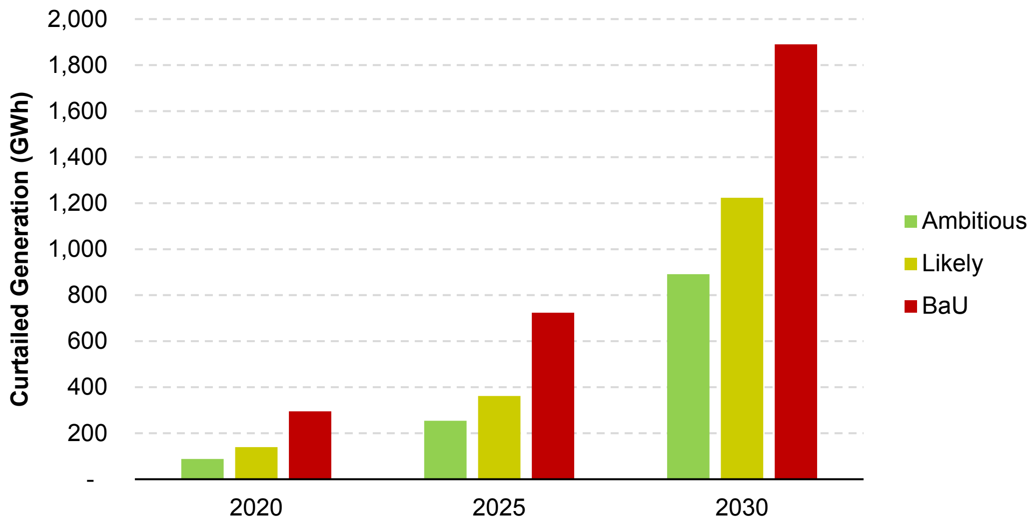
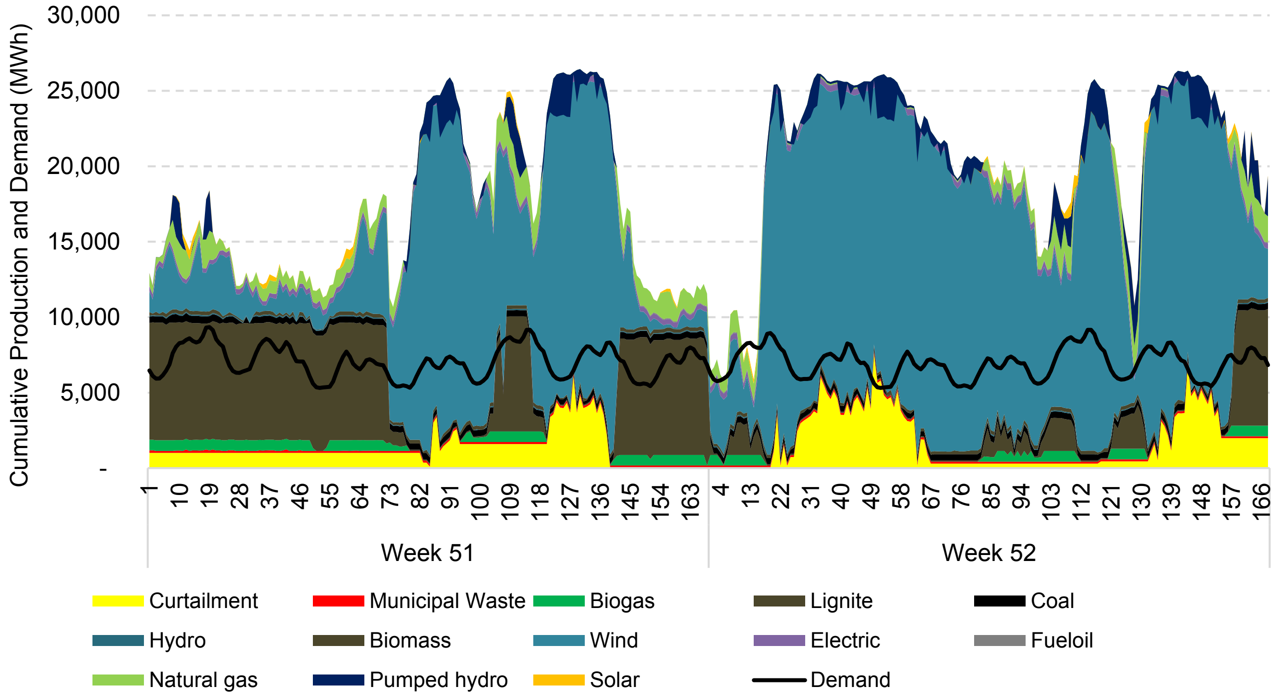


Figure 34. Curtailment levels of land-based and offshore wind by scenario and year in Germany

Looking more closely at the curtailment in two selected weeks in 2030 for central-east Germany (Figure 35), curtailment takes place in hours where the wind production largely exceeds the demand in a certain market region and the transmission lines are saturated by the energy export. The only line that is not exporting at full capacity is the one to northeast Germany, but in those specific hours the price differential between the two regions is zero. Increasing the transmission capacity in those areas where wind power might exceed demand for long periods is key to reducing the amount of wind energy curtailed.



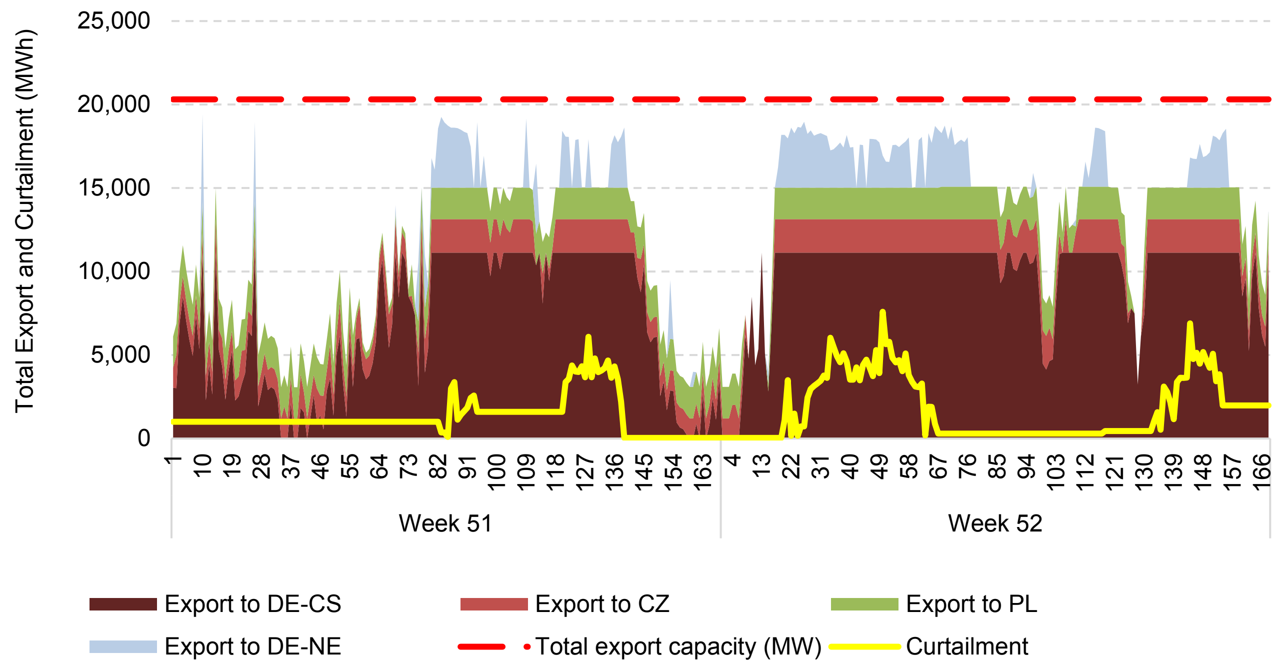


Figure 35. Dispatch in two selected weeks for the region DE-ME in 2030 (top) and export to neighboring regions (bottom)

6.2.4 Variations in Annual Generation and Emissions

Annual generation is affected by the turbine technological advancement in the Likely and Ambitious scenarios. Figure 36 shows the variation compared to the BaU scenario.

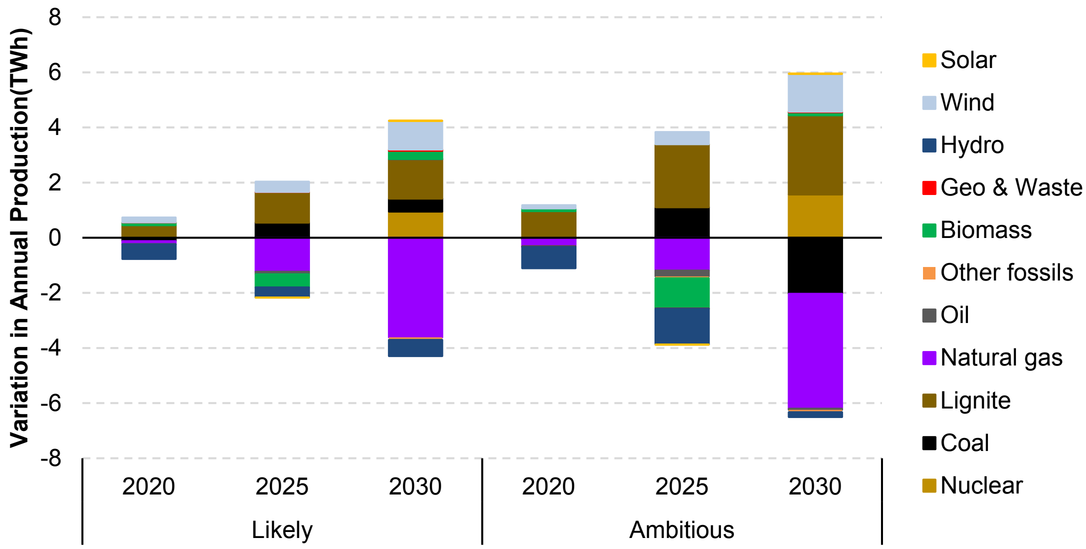


Figure 36. Variation of generation across scenarios in the modeled region, compared to the BaU[21] scenario

In both advanced scenarios, there is a tendency toward increasing baseload generation (nuclear and lignite) and reducing peak generation (mainly natural gas), as explained while describing the residual load duration curve. The increase in wind and solar generation is related to the aforementioned reduction of curtailment.

This change in the generation can have opposing effects on emissions. Reducing curtailment will result in decreased emissions. Alternatively, by substituting natural gas with German lignite in the baseload generation, the emissions increase. In cases where the baseload is provided by technologies with lower emissions than the peak plants, the deployment of advanced turbines can have a net positive effect on total emissions. Additionally, it has to be noted that the wind generation is fixed across scenarios to make them comparable in terms of penetration level. However, if the level of wind was not fixed, the Ambitious scenario could feature a higher level of VRES, thus offsetting the potentially increased emissions[22].

In 2030, total CO_2 emissions in the Likely scenario (498 million tons) are slightly higher than in the BaU (497 million tons) since lignite and coal substitute natural gas to a large extent. In the Ambitious scenario, the emissions (495 million tons) are lower than both the BaU and Likely scenarios, since coal generation is reduced and more nuclear and wind is dispatched.

[21] The differences in hydropower production are related to the way hydropower is modeled and dispatched and it is not directly attributable to the technology choice. This is taken into account and further explained in the section related to calculation of total emissions and system costs.

[22] See also explanation under *Recommendation for Future Research* (Section 8).

6.2.5 Wholesale Electricity Price

The projection of the European power system shows increasing power price levels compared to 2015-2017 (Figure 37). After 2020, the increase in the CO_2 price and the decommissioning of conventional power plants (especially nuclear) cause a price increase in Germany of 22% in 2025 compared to 2020. These projections are highly uncertain by nature, and are affected by the development of fuel and CO_2 prices, technology cost, demand development, and future power market designs.

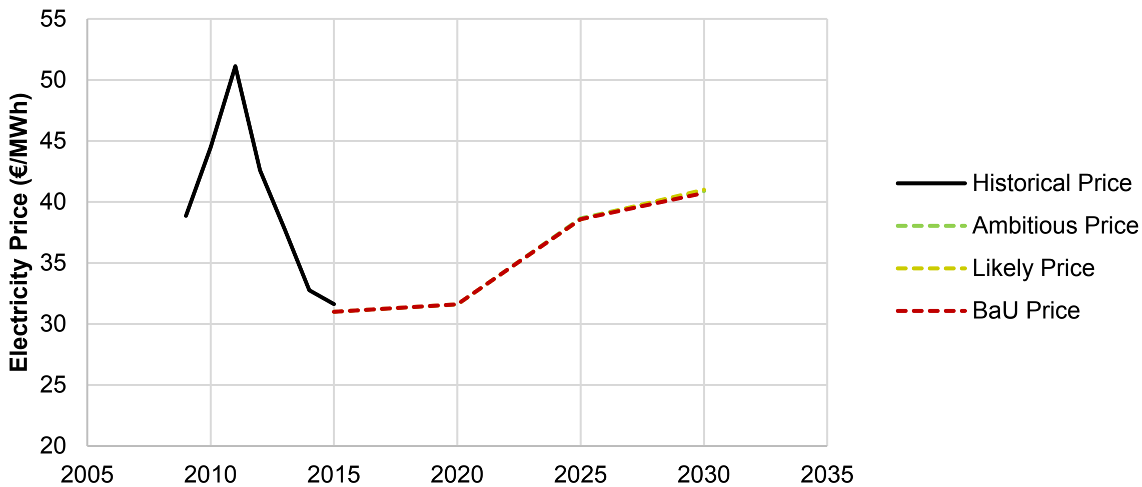


Figure 37. Development of German average wholesale electricity prices (consumption weighted across regions) resulting from the model

Prices are not largely affected by the wind technology scenarios. To give an idea of the magnitude of the price difference, in 2030 the average wholesale electricity prices in Germany[23] differ by less than 1% across scenarios, with a tendency toward higher prices for more advanced designs. This is mainly due to the reduction of the merit order effect at high wind speeds.

Given the change in the wind generation pattern, it is interesting to look at the composition of the price profile (i.e., the electricity price duration curves).

Figure 38 shows the price duration curves for the three scenarios in the DE-NW region in 2030. This specific region is chosen due to the high installed wind capacity, but both the structure and the differences across scenarios are very similar in the other three German regions and in other countries as well.

[23] Since Germany is modeled with four price zones, the average price is demand-weighted across regions.

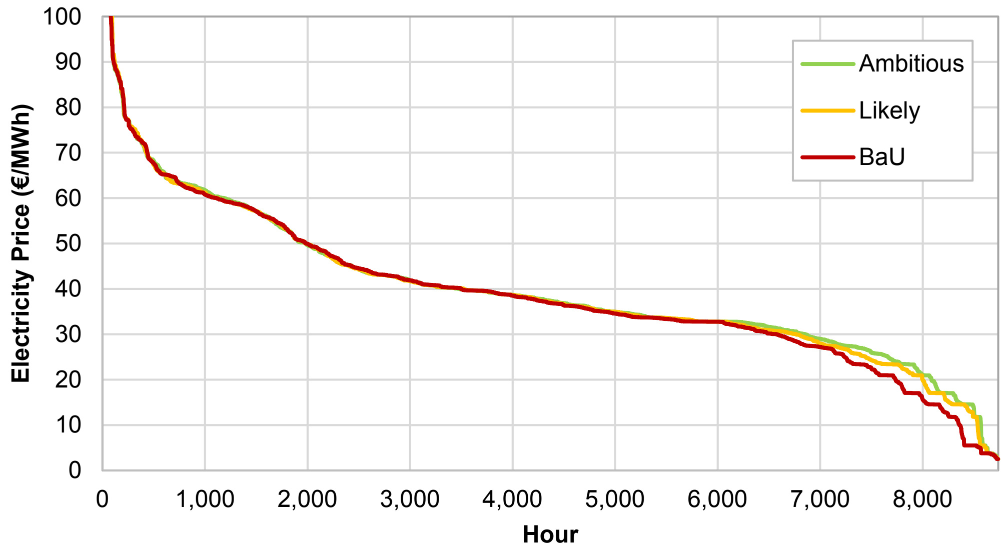


Figure 38. Price duration curve for the DE-NW region in 2030, showing the reduction of the merit-order effect in the market

The advancement of turbine design in terms of specific power and hub height mostly affects the market prices during the 2,500 hours with the lowest price (right end of the graph). This is a direct consequence of the reduced feed-in at high wind hours observed in the wind power duration curve. The lower generation in these hours reduces the merit-order effect significantly, thus ensuring the equilibrium between demand and supply takes place at a higher price. In comparison, the difference of wind generation in the rest of the hours is not large enough to trigger a sufficient shift of merit order and a change in the marginal producing unit.

A price difference in these hours is significant for wind power producers since it is the time in which their production is higher: any increase of price in those hours is reflected in substantially larger revenues.

The price in the lower end of the duration curve is affected by several factors, some of which relate to the bidding behavior of the power producers (which is not modeled in the present analysis). The price in these hours can reach a negative value in the case of strategic bidding, waste-to-power plants bidding with negative marginal cost, must-run units, and subsidies to renewables. If negative prices occur, the market value of wind can be reduced further, and the advantage of advanced designs would be even larger than assessed here. This aspect is further described in Section 7.

6.3 Total System Cost

The main evaluation criterion for the different wind turbine technologies is the possible economic savings on the system level. The economic impacts of the different scenarios are analyzed by calculating the total socio-economic cost related to serving both district heating and electricity demand in the entire modeled system. The total socio-economic cost is derived from the capital cost for all new installation (C_{CAPEX}), maintenance cost (C_{OPEX}), fuel cost (C_{FUEL}), and the socio-economic cost of greenhouse-gas (GHG) emissions (C_{GHG}).

$$C_{tot} = C_{CAPEX} + C_{OPEX} + C_{FUEL} + C_{GHG}$$

Capital cost is calculated using a socio-economic perspective with a real discount rate of 4% and a lifetime of 20 years for all technologies. For the GHG emissions, only differences in CO_2 emissions between scenarios are taken into account, while effects on other GHG emissions or particle emissions are disregarded. Cost of emissions is set equal to the applied ETS price, which has a limited value of 15 €/ton by 2030. Due to the simulation setup, total hydropower can vary between scenarios[24], which is accounted for under "other cost". What these costs represent depends on the type of generation that would substitute the differences in hydro generation, and could thus be distributed across the other categories.

The Likely scenario shows total system savings of more than 850 million €/year by 2030 (Figure 39). The Ambitious scenario shows an additional cost of up to 450 million €/year by 2030. These cost differences correspond to roughly 0.6% savings and 0.3% additional cost compared to the total system cost in the BaU scenario.

A large share of the cost difference is related to differences in both capital and maintenance cost of new wind turbines installed until 2030. In the Likely scenario, the share of the savings related to turbines ranges from 91% in 2020 to 68% in 2030. This also underlines that savings in the remaining system increase as the overall wind penetration increases.

Due to the gravity of the turbine savings, the total system savings are subject to uncertainty based on differences in technology cost for the different turbine designs. On a system basis, both the Likely and the Ambitious scenarios achieve similar savings, but the higher specific wind turbine cost in the Ambitious scenario leads to an additional total cost. Savings in the remaining system are mainly related to fuel savings, arising from the increased use of lower-marginal-cost baseload plants (coal and lignite), which substitute the higher associated fuel cost of natural gas generation. A lower share of the savings in the remaining system is associated with savings in capital cost and fixed operation and maintenance cost, due to a lower need for peak generation plants.

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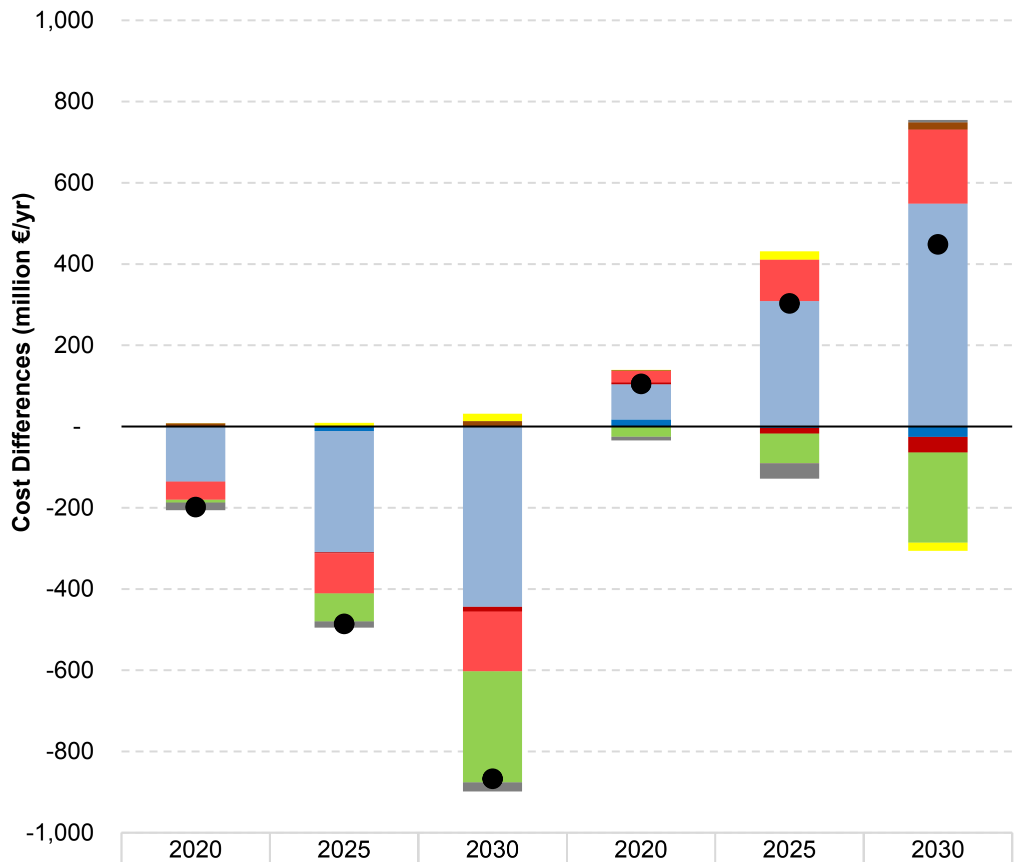
[24] In the model, hydro power with a reservoir is dispatched based on the value of the energy in the reservoir. During the investment run, the model calculates the value of the hydro power during each week of the year and transfers that to the dispatch run. In the dispatch run, the value of the hydro generation determines if the plant should enter the market: when the price is higher than the value of hydro it produces. With different realized prices in the various scenarios, there can be small variations to the total amount of annual hydro generation. This is interpreted as a different hydro reservoir level at the end of the year, which is valued in the economic calculations.



	2020	2025	2030	2020	2025	2030
		Likely			Ambitious	
Other costs	-19	-15	-23	-9	-38	6
Emission Cost	0	7	18	1	20	-20
Variable O&M	6	2	13	2	-0	18
Fuel Cost	-7	-69	-273	-25	-73	-222
Fixed O&M new turbines	-45	-99	-147	29	102	182
Fixed O&M	0	-2	-11	4	-14	-38
Capital Cost new turbines	-136	-299	-444	87	309	549
Capital Cost	1	-11	-0	17	-4	-25
Total costs	-198	-486	-867	105	303	448

Figure 39. Differences in total system cost compared to the BaU scenario. Capital cost is calculated using a lifetime of 20 years and a real discount rate of 4%.

One conclusion that cannot be made is that the Ambitious scenario turbine design is not economically viable; however, only that a rigorous buildout of *only* very Ambitious turbines is not economically efficient, based on the additional specific cost of those turbines assumed in the present study. Depending on the conditions at a specific site, however, the technology can still be relevant, and may become valuable on a more widespread basis if the incremental cost of taller towers and/or larger rotors declines.

Table 7. Distribution of Cost Differences Compared to the BaU scenario on New Turbine Installation and Remaining System. Cost per megawatt-hour is calculated as total cost relative to generation from all new wind turbines installed after 2015.

		Cost Differences Remaining System (M€/year)	Cost Differences Wind Turbines (M€/year)	Total Cost Differences (M€/year)	Total Cost Differences (€/MWh new wind)
Likely	2020	-20	-180	-200	-2.2
	2025	-90	-395	-485	-2.1
	2030	-275	-590	-865	-2.3
Ambitious	2020	-10	115	105	1.2
	2025	-110	410	305	1.3
	2030	-285	730	450	1.2

A threshold value for the additional specific investment and fixed operation and maintenance cost for the turbines applied in the Likely and Ambitious scenarios can be calculated based on the savings in the remaining system and the reduced capacity of the installed land-based turbines. This threshold value indicates the level at which all system savings are offset. Any additional cost beyond the threshold level will lead to additional spending in the scenarios.

The threshold values for the Likely scenario are well above the estimated additional specific costs (Table 8). For the Ambitious scenario, the threshold values are lower than the respective estimated additional costs, which explains why no total savings are reached in this scenario. Specific cost for the Ambitious turbines would need to decrease by 6%-8% before the total system cost would be equal to the BaU scenario. This can be achieved with lower capacity ratings, which increase the number of turbines but decrease the necessary rotor size and the associated increasing marginal cost.

Table 8. Threshold Values for Increased Investment and Fixed Operation and Maintenance Cost Compared to the BaU Scenario. Threshold values are shown for the capacity installed and technology type applied in the given year (e.g., in 2020, turbines in the Likely scenario can be at most 34% more costly than BaU turbines before savings are offset; in 2025, new turbines can be at most 35% more costly, given that the turbines installed previously are 34% more costly).

		Threshold Relative to BaU	Estimated Relative Difference to BaU
2020	Likely	34%	27%
	Ambitious	73%	78%
2025	Likely	35%	28%
	Ambitious	74%	80%
2030	Likely	38%	28%
	Ambitious	77%	82%

6.4 The Effect of Technology on the Market Value of Wind

From a market and developer perspective, advanced turbine design benefits the market value of the wind fleet. As already presented, market value of wind is the average revenue per unit of energy produced by wind, and it represents the capture price of wind in the market. Figure 40 presents the historical values and resultant projections for the different scenarios in terms of both average price and market value of wind in Germany.

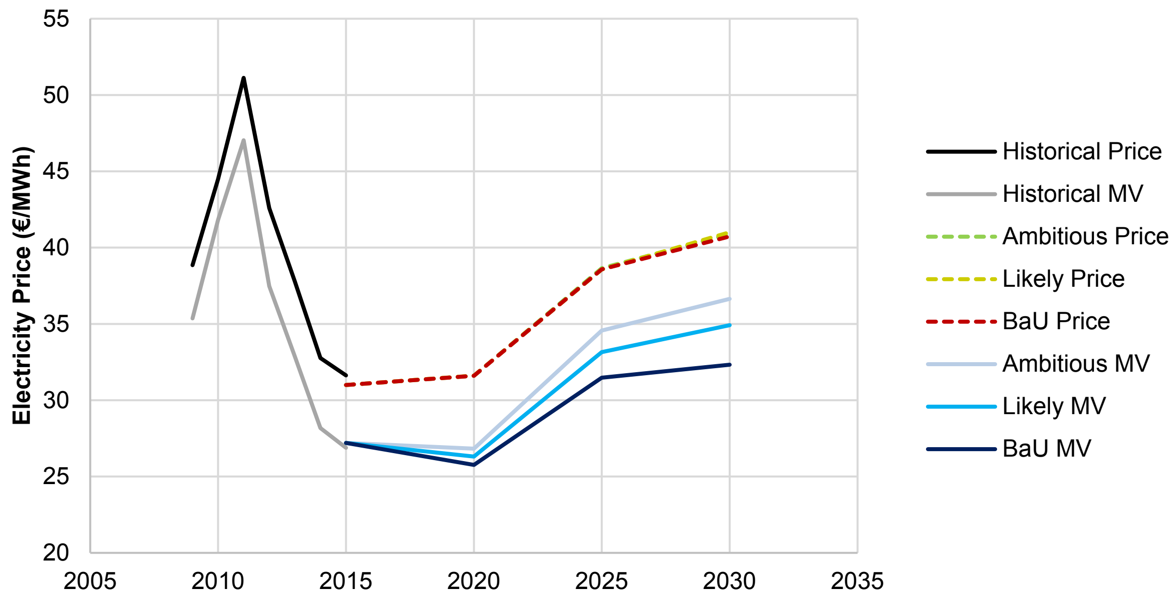


Figure 40. Market value of wind (MV) in Germany by scenario, compared to the average electricity price

Two key observations can be made based on the results. First, the advanced design scenarios achieve higher market values for wind power (the Likely scenario exceeds the BaU scenario, whereas the Ambitious scenario demonstrates the highest market value). Second, the difference in market value between scenarios increases over time—while the discrepancy is miniscule in 2020, it becomes prominent towards 2030. In 2030, the Likely scenario features a market value of wind of 34.9 €/MWh compared to 32.3 and 36.6 €/MWh for the BaU and Ambitious scenarios, respectively. This corresponds to an 8% increase in the market value compared to the BaU scenario, while in the Ambitious scenario the figure is as high as 13%.

Moreover, when looking specifically at the BaU scenario, the difference between the average price and the market value increases over time, confirming the wind value decrease observed in previous literature. To better capture this, the value factor (VF) of wind power is compared across scenarios—a point to which we return in Section 6.4.2.

6.4.1 Rationales for the Value Difference

The difference in the market value of wind can be explained by looking at two parameters: electricity price and production patterns. In Figure 41, the price duration curve is divided into five clusters of equal length in terms of hours and total wind production in each cluster is plotted for each of the three scenarios.

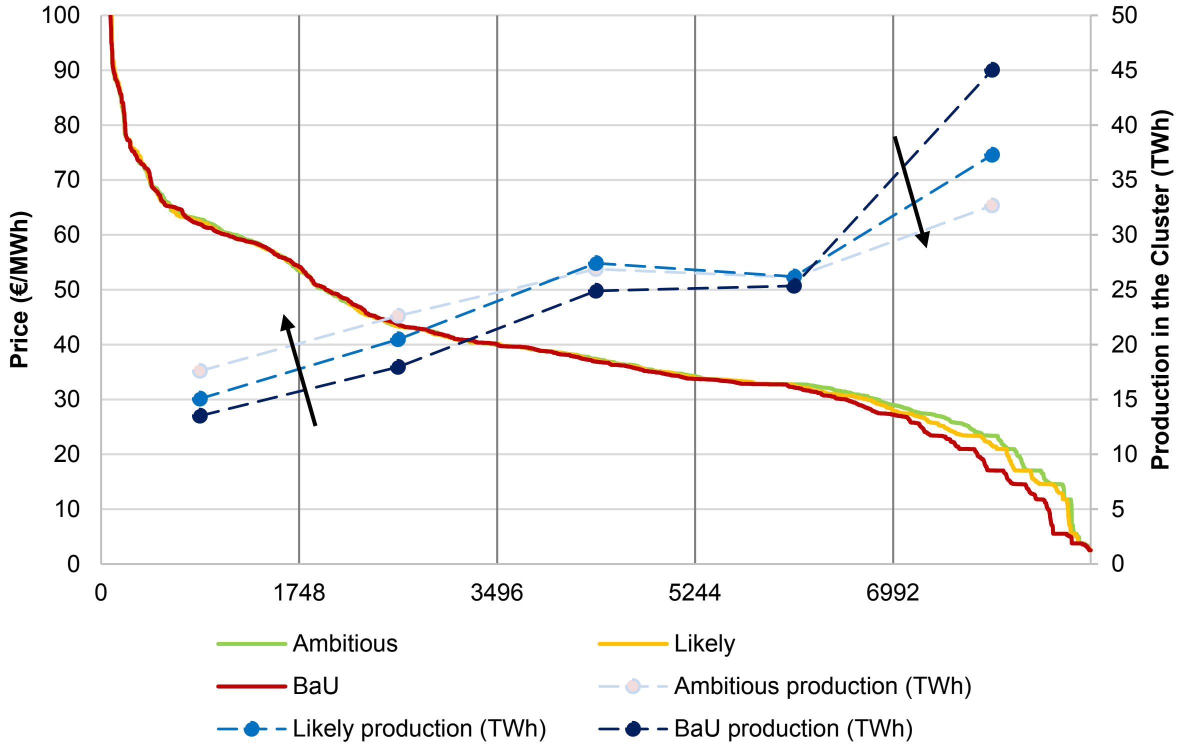


Figure 41. Explanation of the higher value for advanced designs. Total production in TWh (right axis) for each of the five bins of the price duration curve (left axis). The arrows indicate the change in generation from the BaU to the Ambitious scenario. Germany DE-NW, 2030.

The two rationales behind the higher value are made explicit in this graph. First, the wind production is higher in the last bin for all three scenarios relative to other bins; the price is higher in the Likely and Ambitious scenario due to reduced merit order effect. Second, the distribution of production for advanced design turbines is shifted toward hours of higher price.

Not only is the price pressure from the merit order effect lower, but wind production is also shifted to hours with higher prices.

6.4.2 Value of Land-Based Wind in Germany

The resultant value factors for land-based wind in Germany over time, which constitute one of the main messages of the study, are shown in Figure 42 for the three different scenarios. It is notable that the value factor for 2015 (0.88) is slightly higher than the historically realized value factor (0.85). A tendency to overestimate the value factors has been identified and is explained in Text Box 4.

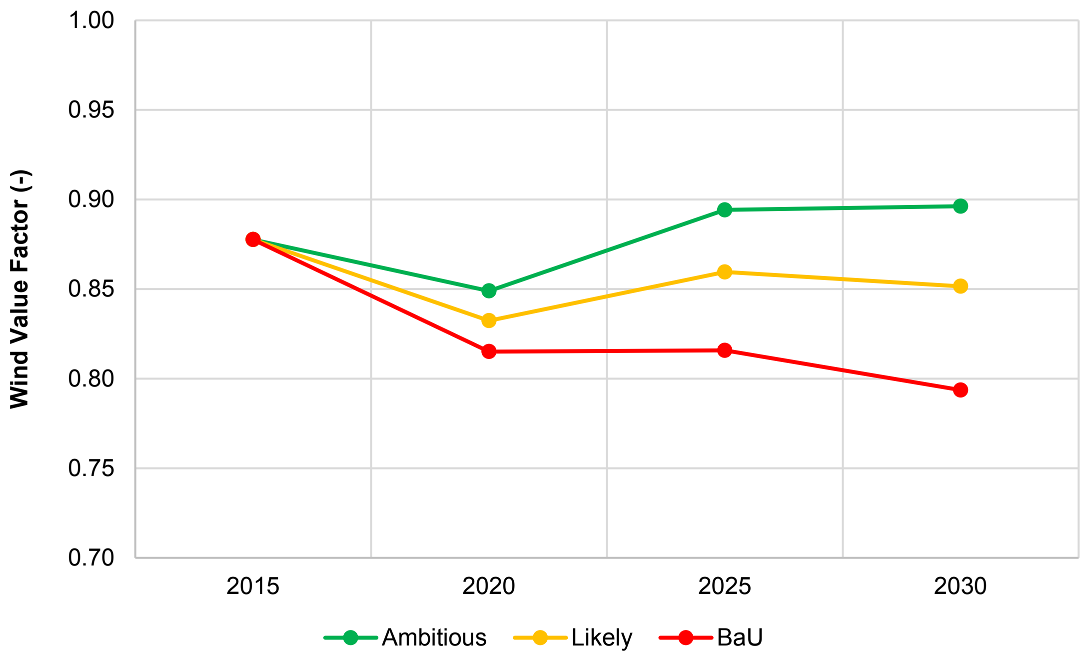


Figure 42. Value factors for land-based wind in Germany for the three scenarios. Between 2020 and 2025, the effect of increased interconnection in the North-South axis is reflected in higher VF.

More importantly, the wind value factor decrease characterizing the BaU scenario is largely reduced in a scenario considering the Likely development of land-based turbines in Europe. In the Ambitious scenario, which assumes extreme design towards low wind speeds, the value factor of wind could become higher in 2030 than in 2015, even with a much larger wind penetration (25% compared to 12%).

In the Likely scenario, the VF stabilizes in 2030 to a level of 0.85, which is 7% higher than in the BaU scenario. The Ambitious scenario features a higher VF in 2030 than it was in 2015 at 0.90, corresponding to a 13% increase in the value compared to the BaU scenario.

This result underlines another important message: failing to take into account the technological development in land-based wind power when analyzing the development of the power system could result in an underestimation of the competitiveness of wind power and its potential contribution to a cost-effective system development.

The network expansion planned for Germany (north-south corridor) and the surrounding countries alleviates congestion problems, thereby contributing to a greater wind power integration and a boost in wind's value factor, especially between 2020 and 2025. As previous studies have underlined, increased interconnection will have a positive effect on the value of wind, and it is an important consideration in long-term power system planning.

Another aspect worth mentioning is the benefit wind power producers receive from technology development, particularly in terms of specific power and hub height. Not only do new land-based wind turbines see a higher price in the market, but the historical fleet of turbines sees increased revenue by 5% and 6% in 2025 and 2030, respectively, as the entire fleet has moved toward lower wind speed designs (Likely scenario).

The increased value of wind is achieved at the expense of conventional dispatchable generators, such as nuclear, coal, and lignite power plants. Figure 43 shows the development of the VF for two generator groups in Germany: baseload (nuclear, lignite, coal) and peakers (natural gas, oil). As illustrated, the value of baseload generators in the market in the Likely and Ambitious scenarios is reduced compared to the BaU scenario, while the same does not happen for natural gas and oil. Regardless of the lower value in advanced wind design scenarios, there is a trend toward higher values in the market for conventional generators over time. The main reason for this evolution is an increased steepness of the price duration curve, due to factors like an increase in renewable feed-in, decommissioning of baseload generators such as nuclear and lignite, and increased natural gas prices.

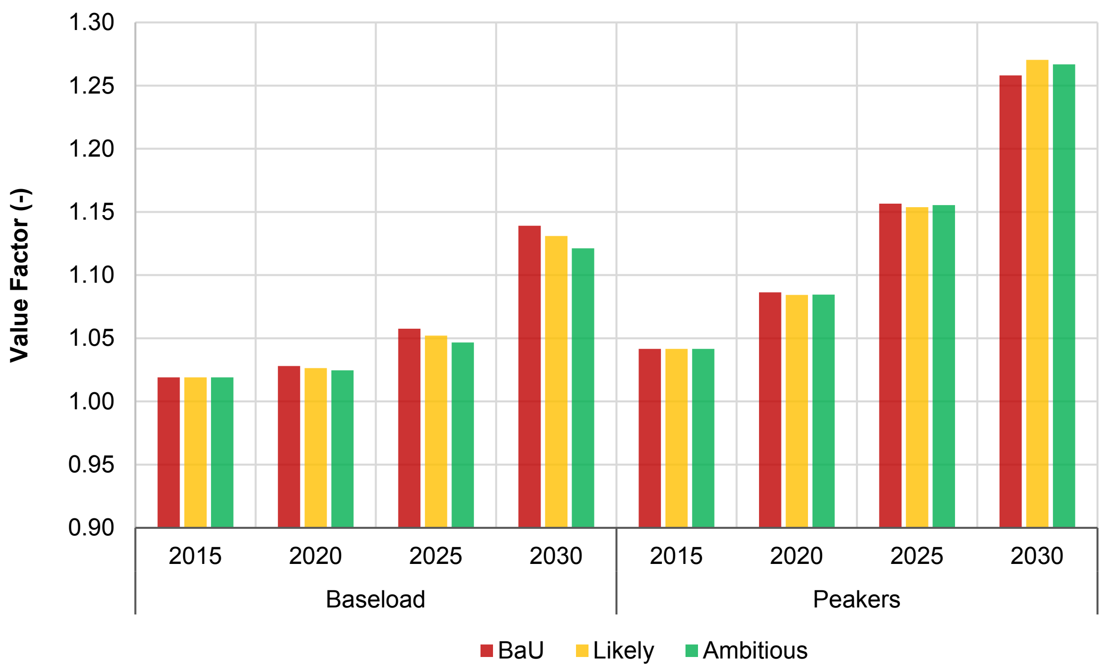


Figure 43. Value factor for conventional generators grouped in baseload (nuclear, lignite, coal) and peakers (natural gas and oil)

Text Box 4. Overestimation of value factors

An observable mismatch occurs when comparing historical value factors with the ones resulting from the model for the year 2015—specifically, that the modeled VFs are slightly higher than the ones realized. For example, in 2015 the historical VF for Germany was 0.85, while the 2015 dispatch simulation yielded 0.88. However, the average annual prices are close to the ones realized.

This discrepancy can be explained by looking at the shape of price duration curves. This mismatch in the price relates to the imperfect nature of dispatch optimizations, which cannot capture the full picture of marginal costs and the strategic behavior of some producers, mainly hydropower-based. The imperfect knowledge of real operations, a certain level of market power, and the speculative behavior of producers would presumably make the price duration curve steeper.

Figure 44 shows price duration curves for Germany, comparing realized market data to modeled results. The slope of the duration curve and the diversification of prices is lower for the modeled results than for historical data. In this study, unit commitment[A] formulation is used, which performs better than a simpler economic dispatch optimization[B] in capturing the price diversification.

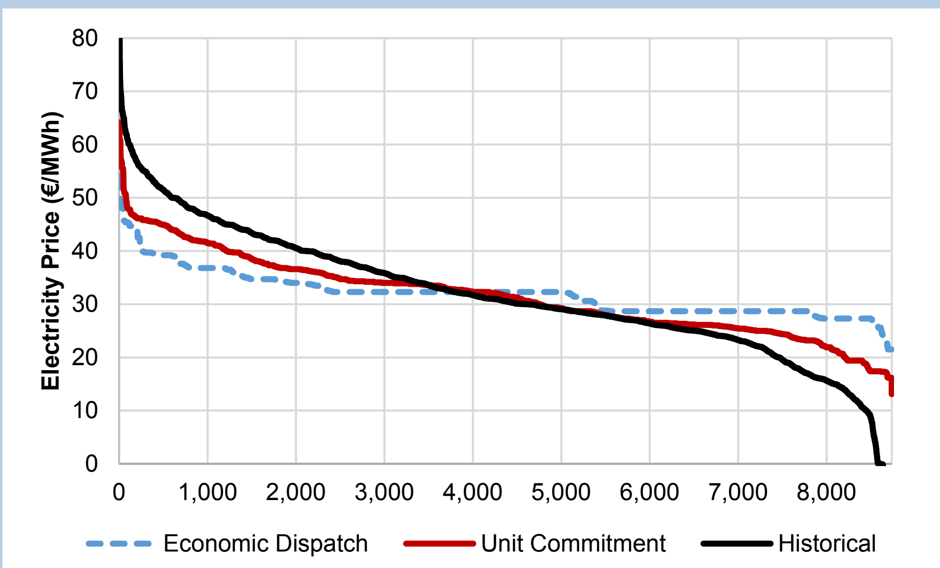


Figure 44. Price duration curve comparison between historical realized prices in Germany and modeled results with economic dispatch (blue dotted) and unit commitment (red)

[A] Unit commitment considers start-up costs and minimum load of thermal power plants, and is formulated as a relaxed mixed integer problem.

[B] Economic dispatch is formulated as a linear problem and do not consider the online/offline status of generators.

Other reasons that could contribute to the overestimation are:

- The level of detail for the conventional generation fleet is not at a single plant level, even though technologies with different efficiencies are modeled as separate entities;
- The way extreme price events are modeled, (e.g., power price reaching value of lost load) and their difference with real market outcome has a considerable impact on the value factor of wind[24];
- Wind is modeled to be representative for a normal wind year, while 2015 was a very windy year, with 13% more wind production than a normal year. Higher wind production would lead to a lower VF, thus reducing the overestimation;
- Only a general seasonal variation of natural gas price is modeled, while for the rest of the fuels there is a single average price throughout the year. This has a large impact especially for a year like 2015 in which very large price fluctuations took place;
- The model considers all energy traded in the day-ahead market, while in reality a number of conventional units operate through over the counter contracts. This likely underestimates the merit-order effect in the market and reduces the number of hours with very low prices.

It must be noted that the overestimation of value factors can result in an underestimation of the relative benefit of advanced wind designs. If all value factors were lower by a certain percentage point, then the relative value of advanced design would increase. However, whether the overestimation affects all technologies equally has not been investigated.

6.4.3 Value of Land-Based Wind in Other Countries

Figure 45 shows the value factor in the Likely scenario for selected countries. In all of them, there is a tendency toward value reduction from 2015 to 2030. As indicated in other studies, those countries with access to hydropower generally have a higher value factor, because dispatchable hydropower can help sustain the value of wind [46].

The main thing to note is that in the simulations carried out, when the likely development of the European power system toward 2030 is taken into account, in terms of interconnection expansions, probable development of RES and likely improvement of wind technology, the wind value drop is not as dramatic compared to today's level.

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[25] This is true for value factors, but the impact is much lower for the market value of wind. Indeed, an increased number of hours with very high prices affect the average price in the market, but not so much the market value of wind, since wind generation is very low in those hours. Therefore, not being able to fully capture the extreme price events in the modeling does not affect the comparison of different technologies in terms of their respective market value.

Denmark, Germany, and Great Britain reach a land-based wind share of 52%, 25%, and 23%, respectively, and their value factor ranges between 0.85-0.93 in the Likely scenario, wherein the land-based technology trend advances as expected.

For context, a previous study by Lion Hirth and Simon Mueller [8] compared advanced turbines (211 W/m^2) to classical turbines (>400 W/m^2) in a thermal system. For classical turbines, the resultant value factor was around 0.80 at 20% penetration level and 0.7 at 30%, respectively, while for advanced turbines the value factor values were 0.85 at 20% and 0.80 at 30%, respectively. The results of the current study estimate slightly higher value factors, despite the Likely technology scenario featuring a higher specific power. However, there are significant differences in the analysis setup of the two studies, which makes a like-for-like comparison of the results not possible.

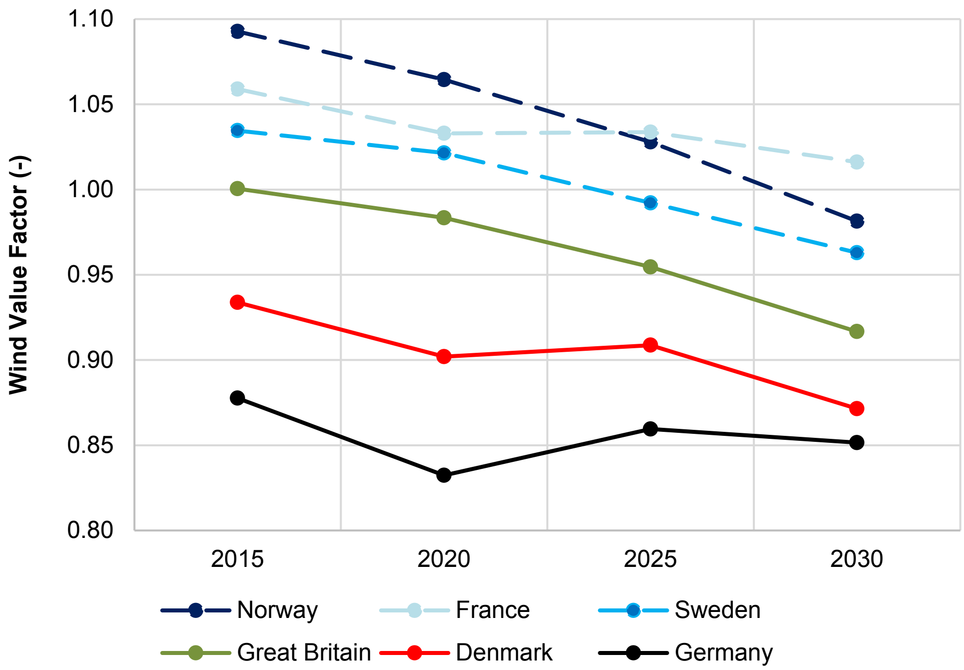


Figure 45. Land-based value factor for different countries in the Likely scenario. Systems with direct access to hydropower are shown with dotted lines.

The results for Sweden and Norway, illustrated in Figure 46, underline the fact that advanced turbine design also ensures a reduced value drop in hydro-dominated countries, where the value of wind is generally higher. The dramatic drop of value in the BaU scenario for Norway, starting from 2025, is due to a large increase in the wind generation, which grows from 4 TWh in 2020 to around 17 TWh in 2025-2030. If advanced wind technologies are deployed, as is the case in the Likely and Ambitious scenarios, this drop-in value is largely reduced. This large drop materializes, even in a country with access to a large hydropower resource, because a large part of the wind development takes place in the northern Norwegian regions, where the electricity demand is low, and the interconnection is not strong.

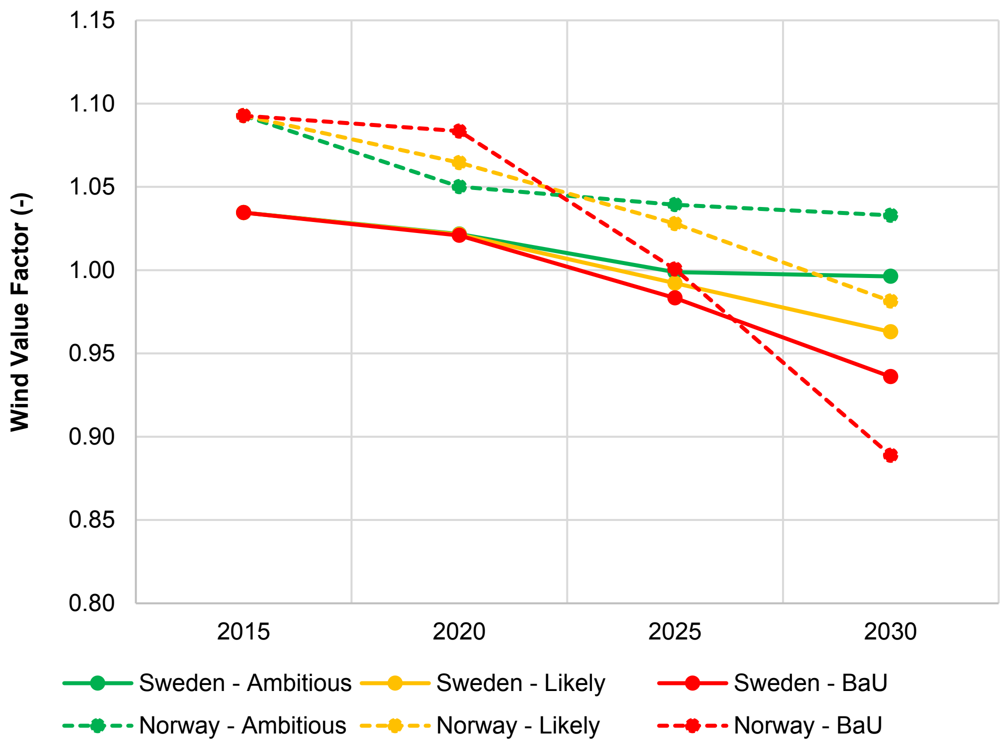


Figure 46. Development of value factors across scenarios in countries with large access to hydropower: Norway and Sweden[26]

6.4.4 Value of Offshore Wind

The technological evolution of offshore wind was not a specific focus of this study. Due to the better wind resource and the generally higher towers, specific power is not projected to diminish at the same pace as land-based wind. Nonetheless, some studies have assessed the economic benefit of the so-called overplanting, or increasing the number of turbines in an offshore wind park without increasing the rated power of the cable to shore. This measure leads to export cable investment savings and an increased specific power for the park as delivered to shore, resulting in higher production at low wind speeds and less volatile output from the park. However, excess power will also lead to a curtailed production at higher wind speeds.

Several analyses have already established that offshore wind power generally features higher value factors, due to the more favorable wind resource and flatter production profiles. Given the framework of this analysis, it is interesting to note how the change of land-based technology affects the value of offshore wind. Figure 47 shows the evolution of offshore value in Germany and Denmark.

[26] The larger value factor of wind in the BaU scenario in 2020 for Norway may seem counterintuitive. This is due to the low wind penetration (only 2%) and the effect of small differences in the hydro dispatch across scenarios.

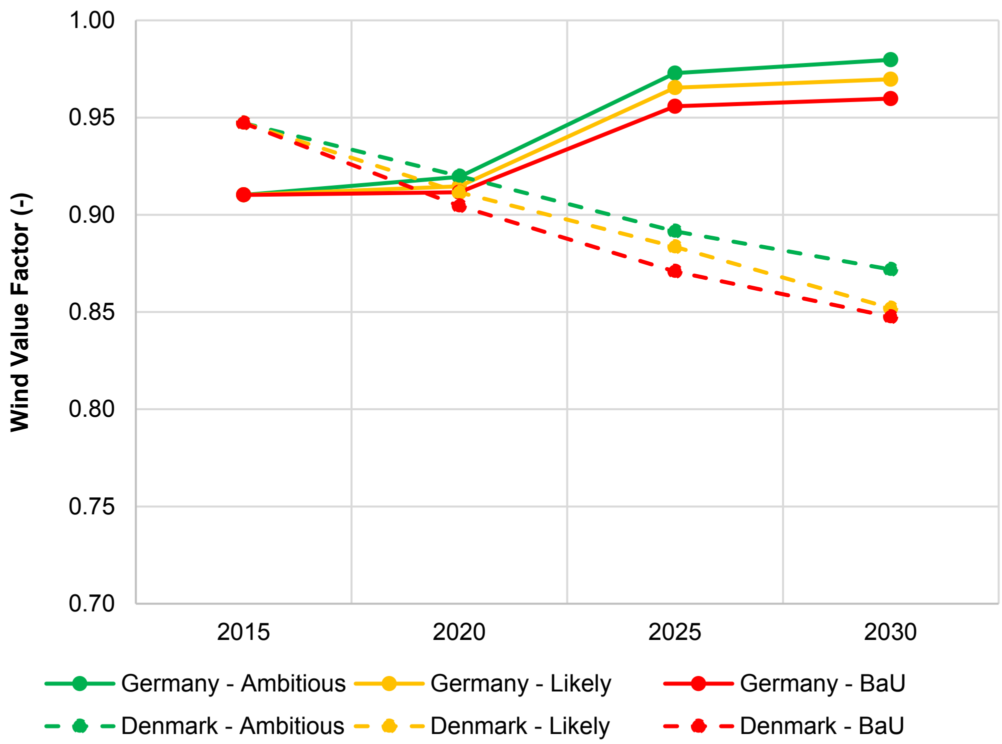


Figure 47. Development of offshore wind value factor in the three scenarios for Denmark and Germany

Given the same offshore and land-based penetration and common system framework, advanced land-based wind designs also increase the value of offshore turbines, regardless of their evolution. The effect is not very large and corresponds to roughly a 2% increase in value, due to reduced production at high wind speeds, which reduces the self-cannibalization effect.

In absolute terms, the development of offshore value factors in the two countries can be explained by considering the following aspects:

- Wind generation in Denmark is very high, reaching around 60% of the total generation for land-based and offshore combined in 2030. Consequently, it becomes more challenging to avoid a value drop for offshore as well;
- In Germany, the relief of congestion in the north-south axis has positive effects on offshore wind value, since additional demand from the southern part of the country can be served by wind production in the north, boosting its value.

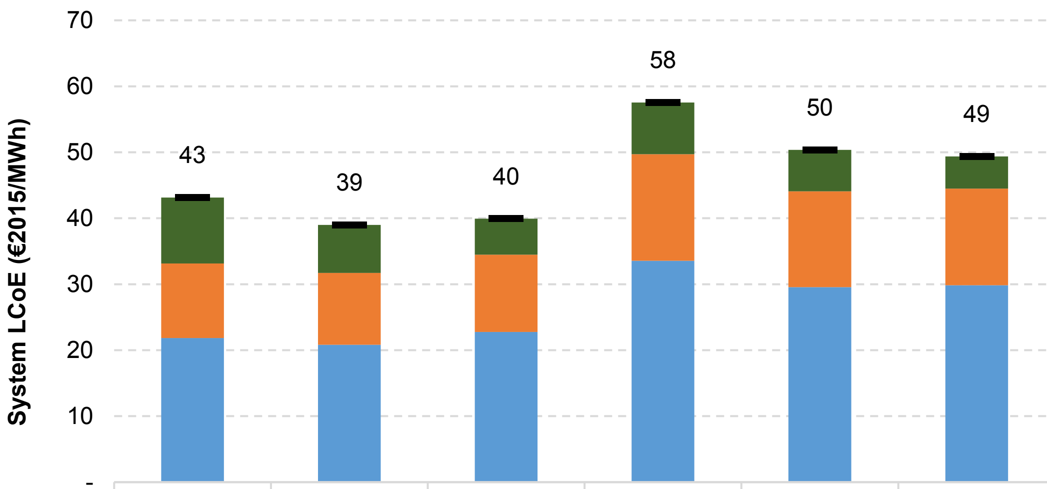
6.5 Levelized Cost of Energy and Site Perspective

Calculations of the levelized cost of energy (LCOE) do not usually consider system effects like market value for variable generation or realizable number of full load hours for thermal generators. However, for variable generation, the difference between the market value and the average market price (profile cost) is a good estimate of integration cost, and it provides an opportunity to include the system perspective in an LCOE calculation.[27] To illustrate this, the LCOE for the different turbine types in the BaU, Likely, and Ambitious scenarios are calculated for northwestern Germany and central-southern Germany (Figure 48). The calculations show the importance of the more site-specific aspects[28] of technology choices and the importance of the profile cost.

In northwestern Germany, the Ambitious turbines have higher LCOE, excluding the system cost. Inclusion of the system cost reduces the differences, although the Ambitious turbines still show higher LCOE. In southern and central Germany, where wind resources are less favorable, the Ambitious turbines show almost equal LCOE excluding system cost, but appear slightly cheaper when including the system cost value. Overall, system cost accounts for 10%-23% of the total LCOE, with the highest share in the BaU scenario in northwestern Germany, where wind penetration is high. The calculations illustrate the importance of considering the system perspective when evaluating economic performance of different wind turbine technologies, and the regional differences regarding the optimal choice.

The LCOE calculations show a socio-economic perspective. Whether a wind turbine developer will evaluate the economic performance in a similar way depends on the distortion of the market signals from subsidy schemes. Simple feed-in tariffs or contract for differences (CfD) would eliminate the effect of the market value for the developer, thereby leading to different technology choices.

[27] The System LCOE metric, formalized in [49], also considers balancing costs and grid-related costs, which are not a specific focus of this study, as part of the total integration cost. However, the profile cost is its major component.
[28] The calculations are done for a market region, which gives a more detailed picture, than the overall system results presented in Section 6.3. Increasing geographic detail in terms wind conditions and shear factor can reveal further differences.



	NW BAU	NW Likely	NW Ambitious	CS BAU	CS Likely	CS Ambitious
System costs	10	7	5	8	6	5
O&M costs	11	11	12	16	15	15
Capital cost	22	21	23	34	30	30
Total LCOE	43	39	40	58	50	49

Figure 48. Estimation of LCOE including system cost in northwestern Germany (NW) and central and southern Germany (CS). System costs include balancing cost of 2 €/MWh and the profile cost from the resulting market value in the different simulations. Assumptions: 4% real discount rate, 30 years of lifetime, technology cost for the year 2030.

6.6 Sensitivities on Turbine Design

A sensitivity analysis regarding the contribution of single parameters, namely specific power and hub height, is hereby presented. Two sensitivity scenarios are performed:

- **hh150**: hub height is increased to 150 m, keeping specific power constant at the BaU level (325 W/m^2)
- **Sp175**: specific power is reduced to 175 W/m^2, keeping the hub height at 100 m.

The first significant thing to observe is the number of full-load hours for the two sensitivities, shown in Figure 49. The average number of FLHs across Europe in the BaU scenario was equal to 2,448. The FLHs reach 2,825 when increasing hub height to 150 m and 3,726 when reducing specific power to 175 W/m^2. This has a direct impact on the necessary wind capacity, the wind feed-in, and the merit order effect and the market value.

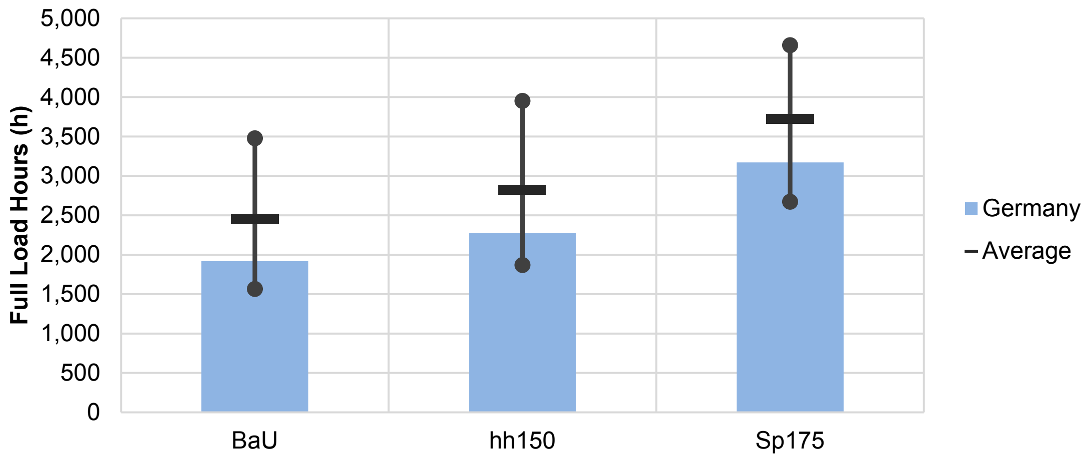


Figure 49. Full-load hour range for the different modeled regions in Europe for the two sensitivities. Average for Germany shown as columns.

When looking at the development of value factors for land-based wind in Germany for the two sensitivities (Figure 50), the value boost of the Ambitious scenario mostly comes from lower specific power. When comparing the value increases of the Ambitious scenario with the BaU scenario, decreasing specific power alone reaches 83% of this improvement, while increasing hub height only 33%.

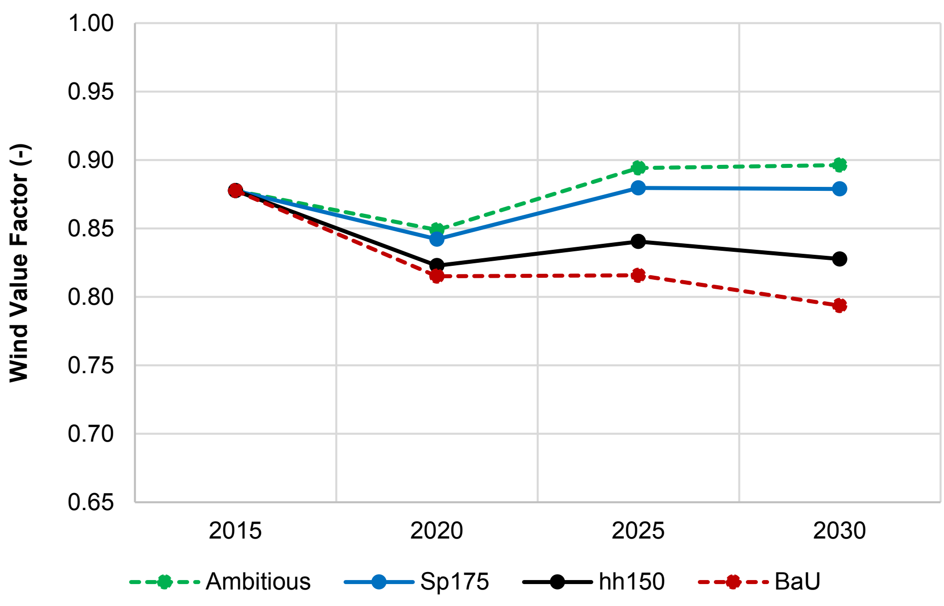


Figure 50. Value factor development for the two sensitivities Sp175 and hh150, compared to the BaU and Ambitious scenarios

The increase in the value factor in the two sensitivities can be related to the additional cost of advanced designs (Table 9). By dividing the additional value in the advanced technology scenario by the percentage increase in cost, it is possible to derive the relative benefit of the technology improvement from the perspective of the market value. For every percentage point of CAPEX increase, the relative benefit in the hh150 scenario is 9%, while in the Sp175 scenario, this figure is equal to 28%.

Table 9. Relative Benefit in Terms of Additional Value per CAPEX Increase for the Two Sensitivities Compared to the BaU and Ambitious Scenarios in 2030

	Value Factor (-)	Additional Value (-)	Investment Cost (k€/Kw)	Cost Increase (%)	Relative Benefit (%)
BaU	0.79	-	882	-	-
hh150	0.83	0.03	1,232	40	**9**
Sp175	0.88	0.09	1,151	30	**28**

7 Discussion and Conclusion

The effects of different land-based wind turbine designs on the European power system have been quantified in the current study, in the context of a projection of the European power system from today toward 2030, with a special focus on the German system.

7.1 European Power System

If the current political agenda on increasing renewable energy shares and mitigating climate change continues, the European power system will undergo dramatic changes leading up to 2030. Both the targets set by the European Union and the national plans for power system development in European countries point toward increasing the penetration of renewable energy in power systems. Projections in this report estimate a total renewable energy share in the European power system[29] that doubles from today's values to more than 60% by 2030. In these projections, 40% of all power generation is based on variable sources from wind and solar power, with land-based wind being the single most important source, accounting for around 17% of all generation.

The projection of the European power system shows increasing power price levels compared to 2015-2017, driven by higher fuel and CO_2 prices and decommissioning of conventional power plants. These projections are highly uncertain by nature, however, as they are affected by the development of a number of critical factors. On average, wind power already yields significantly lower prices in the wholesale market compared to the average market price. In 2015, this difference was around 15% in Germany and Denmark, meaning the value factor of land-based wind power was around 85%.

7.2 Value of Wind

The results suggest that more advanced wind turbine technology designs will positively contribute to the value of wind power in the European power system toward 2030. The advanced turbine design scenarios result in higher market value of wind, or a higher average revenue per unit of wind power produced. In 2030, the Likely scenario features a market value of wind of 34.9 €/MWh in Germany, compared to 32.3 and 36.6 €/MWh for the BaU and Ambitious scenarios, respectively. This corresponds to an increase of 8% in the market value compared to the BaU scenario, while in the Ambitious scenario, the figure is as high as 13%. This is due to lower price pressure from the merit order effect, as well as wind production being shifted to hours with higher price.

7.2.1 Value Factor of Wind Power

In the BaU scenario, the difference between the average market price and the market value of wind is increasing over time, consistent with findings of prior studies on the development of the value of wind. The results for wind value factor development in Germany show that the decrease in the wind value factor, due to higher wind penetration toward 2030, is significantly reduced in the Likely scenario compared to the BaU scenario. In the Ambitious scenario, where extreme design

[29] Countries included: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Netherlands, Norway, Poland, Sweden, Switzerland, the United Kingdom (excluding Northern Ireland).

toward low wind speed turbines is assumed, the value factor of wind is even higher in 2030 than in 2015, despite the higher wind penetration rate (25% compared to 12%).

Toward 2030, the value factor decreases to 0.79 in Germany in the BaU scenario (compared to the corresponding modeled value of 0.88 in 2015). This is an indication of increasing system integration cost. When deploying higher hub heights and lower specific power ratings, the value factor of wind power reaches 0.85 and 0.90 in the Likely and Ambitious scenarios, respectively. The increased value of wind is achieved at the expense of conventional dispatchable generators; their value in the market in the Likely and Ambitious scenarios is reduced compared to the BaU scenario.

The results also suggest that the network expansion planned for Germany (north-south corridor) and the surrounding countries alleviates the presently observed congestion problems, contributing to the integration of more wind power and boosting its value factor, especially between 2020 and 2025. The positive effect of an increased interconnection on the value of wind has been underlined by earlier studies, and is an important consideration in long-term power system planning.

The results of the Likely scenario for other countries in the region (France, Norway, Sweden, the United Kingdom) indicate that there is a tendency toward a reduction in the value factor of wind from 2015 to 2030. Countries with access to hydropower generally have a higher value factor, because dispatchable hydropower can help sustain the value of wind.

But there is a discrepancy between the observed and the modeled value factors for wind for 2015. Specifically, the modeled VFs are slightly higher than the ones realized. For example, in 2015 the historical VF for Germany was 0.85, whereas the 2015 dispatch simulation yielded 0.88, although the average annual prices are close to the ones realized. The discrepancy can be explained by the imperfect nature of dispatch optimizations, which cannot capture the full picture of marginal costs and the strategic behavior of some, mainly hydropower-based, producers.

7.2.2 Impact on the Existing Land-Based Fleet and Offshore Wind

The results suggest that both new installations and the existing land-based wind fleet would benefit from a shift toward lower specific power and higher hub heights for new land-based wind installations. The revenues for the historical fleet in Germany (existing land-based wind turbines as of 2015) would increase by 5% and 6% in 2025 and 2030, respectively, due to the large-scale deployment of advanced wind turbine designs. Since the retirement of the existing turbines is also modeled, the effect of new installations is progressively more prominent over time.

Deploying advanced land-based wind turbine designs will increase the value of offshore wind as well, albeit to a smaller extent, reaching 2%. This is due to decreased production at high wind speeds, which reduces the self-cannibalization effect.

7.2.3 Curtailment

The wind generation that needs to be curtailed in the system is reduced when deploying more advanced wind turbine designs. The results for Germany suggest that the largest reduction of curtailment takes place going from the BaU to the Likely scenario; this results in a 50% curtailment reduction in 2025 and 36% in 2030, respectively. Going from Likely to Ambitious technology, the curtailment is reduced to a lower extent (around 30% additional reduction).

7.2.4 Capacity Credit of Wind Power

Analyzing the capacity credit of land-based wind confirms results from previous studies. For example, the analysis confirms that increased capacity factor and advanced wind turbine technology leads to a higher capacity credit, expressed in relative terms, across all wind penetration levels. In the Ambitious scenario, the capacity credit is increasing over time, irrespective of the increasing installed wind power capacity and penetration level.

However, there is a negligible difference between the scenarios in terms of reduced need for thermal capacity. This can be explained by the fact that the peak in the residual load duration curve takes place during hours of low wind speed. Advanced technology increases production in intermediate wind conditions and produces less in the low wind hours. Consequently, the higher capacity credit in the advanced wind turbine design scenarios is due to a lower installed wind power capacity. The current analysis should only be regarded as illustrative, and additional critical parameters should be considered when assessing the capacity credit of variable power sources.

7.3 Cost and Benefit Perspective

The results indicate that the value of wind can increase with the deployment of advanced wind turbine technology. However, the additional costs of these technologies should also be considered when evaluating the impact of their deployment.

7.3.1 Advanced Technology Cost Threshold

The results of the advanced wind turbine technology scenarios indicate that savings from an overall system perspective arise from both lower cost for land-based wind deployment (as a lower installed capacity can deliver the same generation) as well as from savings from changed generation and investment patterns in the remaining system. These are mainly related to fuel savings, due to a lower need for medium- and peak-load operation and, to a lesser extent, reduced need for conventional generation capacity.

Based on the system-level savings quantified, advanced wind turbine technology cost threshold values were calculated, such as the additional specific investment and fixed operation and maintenance costs level that offset the system-level savings. Additional wind turbine technology costs beyond the threshold value would lead to systemwide socio-economic losses in the scenarios.

The threshold values range between 34% and 38% in the 2020 to 2030 period for the Likely scenario, and 73% to 77% for the Ambitious scenario.

7.3.2 Total System Costs

In order to evaluate total system costs, the increase in specific cost (investment and maintenance cost in €/MW) for higher towers and larger rotors has been estimated. However, this estimate is associated with a high degree of uncertainty because of insufficient data availability. By 2030, these effects have been estimated to increase wind turbine specific cost by 28% and 82% in the Likely and Ambitious scenarios, respectively. For the Likely scenario, the threshold cost values are well above the estimated additional specific costs. In contrast, the threshold values are lower than the respective estimated additional costs in the Ambitious scenario, meaning that no systemwide savings would be achieved. Specific costs for the Ambitious turbines would have to be reduced by approximately 6% to 8% before the total system cost would be equal to the BaU scenario.

The Likely scenario shows total system savings of up to 850 million €/year by 2030. The Ambitious scenario, on the other hand, shows additional costs up to 450 million €/year by 2030. These cost differences correspond to approximately 0.6% savings and 0.3% additional cost compared to the total system cost in the BaU scenario.

A large share of the cost difference is related to both the capital and maintenance costs of new wind turbines installed until 2030. In the Likely scenario, the share of turbine-related savings ranges from 91% in 2020 to 68% in 2030. This underlines the fact that savings in the remaining system increase along with the overall wind penetration.

Although turbine savings are of great importance, the total system savings are subject to uncertainty based on differences in technology cost for the different turbine designs. On a system basis, both the Likely and the Ambitious scenarios achieve similar savings, but the higher specific wind turbine cost in the Ambitious scenario leads to an additional total cost. Savings in the remaining system are mainly related to fuel savings, arising from the increased use of baseload plants (coal and lignite); the baseload plants substitute for natural gas generation, which has a higher associated fuel cost. A much lower share of the savings in the remaining system is associated with savings in capital cost and fixed operation and maintenance cost, due to a lower need for peak generation plants.

7.3.3 System vs. Specific Project Perspective

Optimal wind turbine designs will vary widely across Europe depending on site conditions. Even though the Ambitious scenario (with the advanced technology cost estimation approach applied) does not result in benefits for the overall system, the turbine design can still be a relevant choice. The results of an illustrative example of LCOE estimates for northern and southern Germany indicate that the lower wind resource and the system cost savings make the Ambitious technology favorable in southern Germany, compared to the other two options. In northern Germany, however, the savings in system cost under the Ambitious scenario are offset by higher technology cost.

Therefore, it cannot be concluded that the Ambitious scenario turbine design is not economically viable. It is only conclusive that that the rigorous buildout with *only* very Ambitious turbines may not be economically efficient. Depending on the conditions at specific site and future cost developments, the technology can still be relevant.

In the case of northwestern Germany, the Ambitious turbines have higher LCOE excluding the system cost. Inclusion of the system cost reduces the differences, but the Likely turbines still show lower LCOE. In southern and central Germany, where wind resources are less favorable, the Ambitious turbines show almost equal LCOE excluding system cost, but appear slightly cheaper, when including the system cost value. Overall, system cost accounts for 10% to 23% of the total LCOE, with the highest share in the BaU scenario in northwestern Germany, where wind penetration is high. The calculations illustrate the importance of considering the system perspective when evaluating the economic performance of different wind turbine technologies, and the regional differences regarding the optimal choice.

7.4 Lower Specific Power vs. Higher Hub Heights

The results indicate that lower specific power contributes most to the value factor increases of the Ambitious scenario. Considering 100% of the value increase of the Ambitious scenario compared to the BaU scenario, decreasing specific power alone reaches 83% of this improvement, while increasing hub height reaches only 33%.

When relating this to the cost, the advantage at a system level is even higher: the increase in the value per additional CAPEX is equal to 9% for increase of hub height and 28% for reduction of specific power.

However, this does not take into account any site-specific consideration. Indeed, some sites might have a larger incentive and value boost to increase hub height due to specific orography and roughness considerations.

7.5 Implications for Policy

The findings of this analysis highlight the importance of technology design considerations when evaluating the value of wind power generation, and the need to consider both cost and value perspectives. This is true for both policy and decision-makers as well as wind power developers. Not considering the options for advanced turbine design could lead to an underestimation of the value of wind power in the power system, subsequently impacting considerations of adequate targets for renewable energy penetration levels in the future European power system.

7.5.1 Design of Subsidies

The topic of wind turbine design is also important when designing subsidy schemes. There is a significant risk that subsidy schemes could impact market signals on the value of wind power, meaning that developers will not be able to make optimal technology choices. Historically, policy support schemes have sometimes sought to maximize the capacity or output of the turbines rather than optimizing turbine design considering both cost and value (i.e., “system LCOE”).

Incentives based on a total number of full load hours of production are one example of this potential distortion. Indeed, when space is a limited—which might be the case for land-based wind—incentivizing a certain amount of FLH could induce investors and planners to oversize the capacity of a plant to get the maximum total incentive possible, rather than focusing on optimizing the design for minimizing system LCOE. Typical subsidy schemes that ensure a partial level of market exposure and therefore more market-based value signals are feed-in premiums and green certificate obligations.

However, if developers receive a fixed tariff regardless of their own market value, they will not have an incentive to optimize turbine choice with respect to market value. CfDs, which are a common subsidy scheme used across Europe (especially within renewable auctions), can be designed to ensure a certain market exposure. If poorly designed, however, a CfD will have the same impact as a fixed feed-in tariff. Therefore, under support schemes impermeable to price signals, the reduced market value becomes an externality [5]. This will result in an increased cost of policy support. Other arguments often referred to in discussions on subsidy design include the impact of market risks. However, the effect of technology choices on market risks has not been analyzed as a part of this study.

In Denmark, the support scheme for land-based turbines introduced in 2014 and expiring in 2018 remunerates turbines for a certain amount of FLH, but the number of incentivized hours increases based on the rotor size in terms of m^2, which provides a direct incentive to reduce the specific power[30]. Whether the reduction of specific power experienced in Denmark was due to the subsidy or to general technology improvement has yet to be determined. However, it may be an example of progress toward incentivizing system-friendly design.

In Germany, the setup for the CfD offers an advantage for investors to go lower in specific power and consider the value of the electricity generated when making investments. In practice, the level of subsidy to be paid on top of direct market revenues is calculated as a difference between the agreed strike price and the average monthly reference market value of the specific RES technology. This means that one single market value for land-based wind is considered. A producer with a lower specific power turbine, who already sees a higher price in the market, will receive the same remuneration as another land-based plant with a higher specific power, thus increasing its income.

An analysis of investment behavior [7], however, has shown that this support scheme alone may fail to convey enough incentive to project developers to opt for advanced wind power designs. Current results suggest that the incentive given by the projected market value reduction of wind in the future might be clear from a policymaker perspective, but it is not enough to drive a significant change in investment decisions. Currently, the two largest limits for investors to take actions in this direction are imperfect foresight and financing constraints [7].

7.5.2 Subsidies at Negative Price

Subsidies at negative prices are another interesting consideration in the market. Negative prices may materialize in day-ahead markets (e.g., when wind and solar set the price at their marginal cost, which is equal to variable O&M cost minus the subsidy level). The frequency of this effect could increase in the near-term future, due to higher wind and solar penetration, thereby increasing events of negative prices.

The subsidy-induced negative price hours have an impact on the market value of wind as well. In Figure 51, an example of price duration curve for two dispatch simulations is shown with and without subsidies[31]. When considering subsidies at negative prices, a price gap appears in the low side of the duration curve during those hours where subsidized RES set the price as marginal production units. The level of this "price gap" depends on the value of the subsidy. As wind production is highest in those hours, the market value of wind is significantly affected downwards.

[30] The formula used to calculate the total amount of electricity incentivized considers a base amount of FLH equal to 6,600 and a top up depending on the rotor area, as follows [50]:

$$Production\ incentivized\ [MWh] = 6600\ [h] * Rated\ Power\ [MW] + rotor\ area\ [m^2] * 5.6\ [MWh/m^2\}$$

[31] An indicative level of subsidy of 25 € has been assumed for illustration purposes only.

The more RE in the system, the more hours they will be price setting, potentially amplifying the effect.

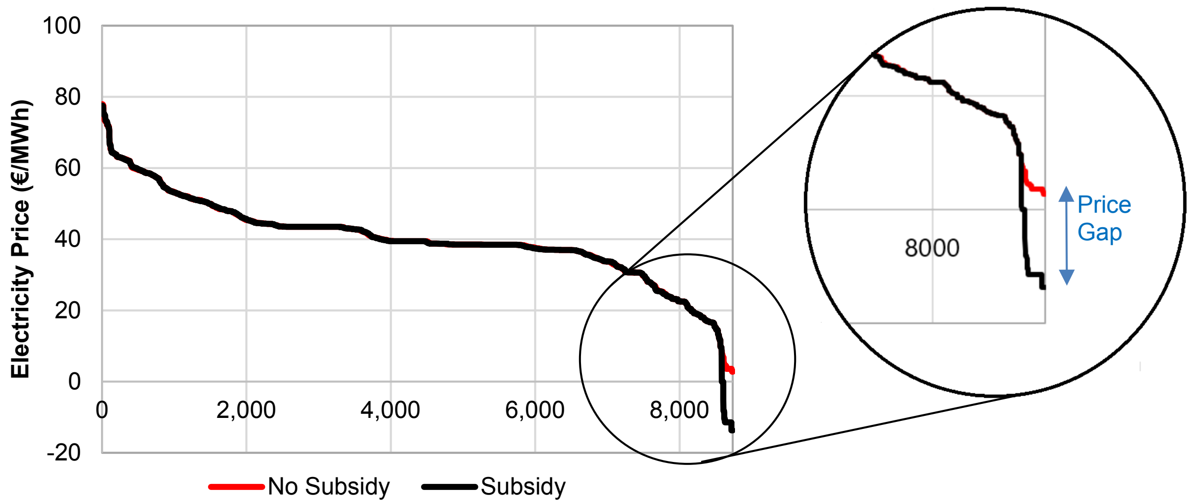


Figure 51. Illustration of the effect of subsidies at negative prices on the price duration curve. A price gap is formed on the lower part of the price duration curve, where RES are marginal producers.

In some countries, such as Denmark and Germany, the idea of providing a subsidy at negative prices is being questioned. Incentives to land-based plants at negative prices are still being provided in Denmark, while the offshore tenders specify that no incentive is paid at negative prices. Germany has adopted a different strategy: the so-called *6-hours rule*. Under this regulation, if the price is negative for six or more consecutive hours, RES producers get no subsidy and bare the negative price only.

In the design of future subsidy schemes, this aspect should be taken into account, acknowledging that subsidies can distort optimal dispatch. A socio-economic optimal dispatch from market incentives can only be achieved if market signals include all externalities. To support the tendency toward market-driven dispatch, the "Guidelines on State Aid for Environmental Protection and Energy 2014–2020" [47] call for more market-based support mechanisms, and specify that "measures have to be taken to avoid renewable generators producing electricity under negative prices."

7.5.3 Grid Cost

Grid connection cost can be affected by technology choices, as they can affect the installed capacity and the need and cost for grid capacity. For different reasons, grid connection costs are not always paid by the wind turbine developer. This means that possible incentives for choosing lower specific power turbines, such as those arising from lower grid connection costs, will not be taken into account by the developer. Payment for grid connection costs, especially possible costs for other grid reinforcements, is a larger topic that is not analyzed in detail here.

8 Recommendations for Future Research

- The current analysis has focused on the effect of advanced wind turbine technology on the value of wind in the case of growing (but fixed across scenarios) wind penetration levels. However, given the increased value in the market and the system benefit of advanced technologies, scenarios in which higher wind share is allowed in the system could be explored. This would be particularly relevant to quantify the extra amount of wind energy and the additional GHG emissions that could result in the system due to advanced designs.
- Other integration measures have not been explored in the current analysis. It would be highly relevant to investigate the impact of measures like storage, electric vehicles, and increasing interconnectivity level in Europe on the value of wind in the context of the application of advanced wind turbine technologies.
- The current analysis setup assumes uniform deployment of specific advanced wind turbine technologies for all new installations across Europe. A more realistic setup with a distinction between different wind turbine technology designs, depending on the specifics of the individual site/region, would also be a relevant contribution.
- The calculations on the economic benefit of the different scenarios showcase the importance of different turbine design costs. In the current study, estimates of cost differences are based on extrapolation of available data for existing turbines. More research on the cost differences of individual turbine components and turbine performance in terms of maintenance cost and lifetime considerations would enable firmer estimates of the expected cost differences.
- The current study has not explicitly evaluated how the grid cost evolution is based on technology choices. Lower wind power capacity in the system, as a result of lower specific power machines, can affect both the need for transmission and distribution grid capacities and the cost of connecting the individual turbines. However, the following effects are implicitly included in the calculations in the current study:
  - Grid connection costs are a part of the investment cost considered for single turbines. Thus, lower total installed capacity also implies some savings on grid connections. However, the differences in cost-per-megawatt installation capacity for different turbine types has only been evaluated as total sum, and not for individual components.
  - The transmission grid assumptions are the same across scenarios. Thus, the Ambitious scenario benefits from being able to use the transmission grid more effectively, since the needed amount of transmission due to wind power generation is lower.
- The current analysis is based on a deterministic modeling approach, and the effects of wind turbine technology on probabilistic topics have not been investigated.
  - The current analysis uses wind speed time series representative of a “normal” wind year. However, iterations incorporating inter-annual variations could provide

further insights on other potential benefits of advanced turbines from a system perspective, such as mitigating the generation drop during low wind years.

- As for wind power, hydropower generation is based on a "normal" year. Differences in market value of different wind turbine technologies can vary in years where more or less hydropower is available as a result of the meteorological conditions. This is especially true for the Scandinavian system, which is highly influenced by hydropower. Iterations on different hydro years could add information on the value of different types of turbines across different meteorological conditions.

- Effects of wind turbine technology on forecast performance have not been investigated. Turbines with lower specific power can have different effects on forecasts and balancing cost. Low specific power turbines operate at rated power more often, allowing better forecasts when wind speed is predicted to be above the rated wind speed. On the other hand, the relative rate of generation changes is higher below rated power, since rated power is reached at lower wind speeds. This increases the relative gradient of the power curve, making forecasts less precise for wind speeds below rated power. However, the maximum installed wind capacity is lower in a system that widely applies low specific power turbines compared to a system with high specific power machines delivering the same generation, which offsets the effect to some extent.

- By simulating dispatch in scenarios with different fuel and CO_2 prices, the short-term effect of those parameters on the value of wind could be further analyzed.
- Finally, additional sensitivity scenarios exploring parameter variations on key factors such as fuel prices, CO_2 price development, and power demand development would provide additional insights on the robustness of the current findings.

Glossary

Specific power

The ratio between the rated power of the turbine in W and the swept area expressed in m^2. Specific power is a crucial component in the definition of a wind technology since it directly affects the shape of the power curve and determines its production potential at different wind speeds.

$$SP = \frac{P_{rated}[W]}{\pi \cdot (D[m]/2)^2}$$

Hub height

In a horizontal-axis wind turbine, it represents the distance of the rotor shaft from the turbine platform and describes how high the turbine stands above the ground. This parameter does not directly affect the shape of the power curve, but it influences the wind resource seen by the turbine and thus the wind production.

Market value of wind

Expressed in e/MWh, it is the ratio between the revenue of wind power in the market in a certain time period and its potential production including curtailment. It represents the average revenue per energy unit of wind produced. In order to capture the characteristic seasonal variation of wind, market value is usually expressed in a yearly time frame.

$$MV_{g,z} = \frac{\sum_t^T p_{t,z} \cdot E_{t,g,z}}{\sum_t^T E_{t,g,z}} = \bar{p}_{g,z}$$

where:
t = time step (1, …, T)
g = technology (land-based wind, offshore wind, solar, …)
z = market zone or country considered (DK1, DK2, France, …)
T = total time steps in the period considered (8,760 if a year is assumed)
E = potential energy production, including production that is curtailed
p = market price in the zone/country considered

Value factor

This parameter is used to express the market value in relative terms, with respect to average day-ahead market price (time-weighted). It is the ratio between the market value in a certain market zone or country and the respective average wholesale electricity price. The value of wind represents the price "seen" by the wind producers in the market, with respect to average system price.

$$VF_{g,z} = \frac{\bar{p}_{g,z}}{\bar{p}_z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z}) / \sum_t^T E_{t,g,z}}{\sum_t^T p_{t,z} / T}$$

where:
$\bar{p}_{g,z}$ = technology-weighted average price (i.e., market value)
$\bar{p}_z$ = average price in the market zone/country

Levelized cost of energy

This parameter expresses the cost of the megawatt-hours generated during the lifetime of the plant, and it represents a life cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}}$$

where:
I_0 = overnight cost or investment cost [€]
N = technical lifetime of the plant [years]
V = variable cost including O&M, fuel, CO_2 costs [€ in year t]
E = electricity produced in the year t [kWh in year t]
i = real discount rate [%]

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Appendix 1

Applied wind turbine cost. See Section 4.3.1 for further explanation. Some of the turbine configurations in the sensitivity scenarios are unrealistic in terms of diameter and hub height combination. However, the same specific power could be achieved by a smaller rotor and smaller generator, possibly at the expense of some advantages from economy of scale, but with the benefit of cheaper rotors.

Table A1. Wind Plant Cost Assumptions

Scenario	Year	Rated Capacity (MW)	Diameter (m)	Investment Cost (k€/kW)	Fixed O&M (€/MW)
BaU	2015	3.50	117	1.104	26.377
Specific power: 325 W/m^2	2020	3.50	117	1.015	24.625
Hub height: 100 m	2025	3.75	121	949	23.171
	2030	4.00	125	882	21.704
	2050	5.00	140	745	18.927
Likely	2015	3.50	134	1.405	33.595
Specific power: 250 W/m^2	2020	3.50	134	1.293	31.365
Hub height: 125 m	2025	3.75	138	1.214	29.644
	2030	4.00	143	1.134	27.886
	2050	5.00	160	971	24.689
Ambitious	2015	3.50	160	1.967	47.024
Specific power: 175 W/m^2	2020	3.50	160	1.810	43.902
Hub height: 150 m	2025	3.75	165	1.710	41.763
	2030	4.00	171	1.607	39.527
	2050	5.00	191	1.406	35.748
HH125	2015	3.50	117	1.283	30.656
Specific power: 325 W/m^2	2020	3.50	117	1.180	28.620
Hub height: 125 m	2025	3.75	121	1.103	26.929
	2030	4.00	125	1.025	25.225
	2050	5.00	140	865	21.997
HH150	2015	3.50	117	1.541	36.837
Specific power: 325 W/m^2	2020	3.50	117	1.418	34.391
Hub height: 150 m	2025	3.75	121	1.325	32.359
	2030	4.00	125	1.232	30.311
	2050	5.00	140	1.040	26.432
SP250	2015	3.50	134	1.209	28.906
Specific power: 250 W/m^2	2020	3.50	134	1.113	26.987
Hub height: 100 m	2025	3.75	138	1.044	25.506
	2030	4.00	143	975	23.994
	2050	5.00	160	836	21.243
SP175	2015	3.50	160	1.409	33.672
Specific power: 175 W/m^2	2020	3.50	160	1.296	31.436

Scenario	Year	Rated Capacity (MW)	Diameter (m)	Investment Cost (k€/kW)	Fixed O&M (€/MW)
Hub height: 100 m	2025	3.75	165	1.225	29.904
	2030	4.00	171	1.151	28.303
	2050	5.00	191	1.007	25.597

Appendix 2

The smoothing factor, K_w, for the different regions is shown in Figure A1. A lower value results in a more smoothed power curve. Lower levels of K_w are related to lower specific power and to larger regions.

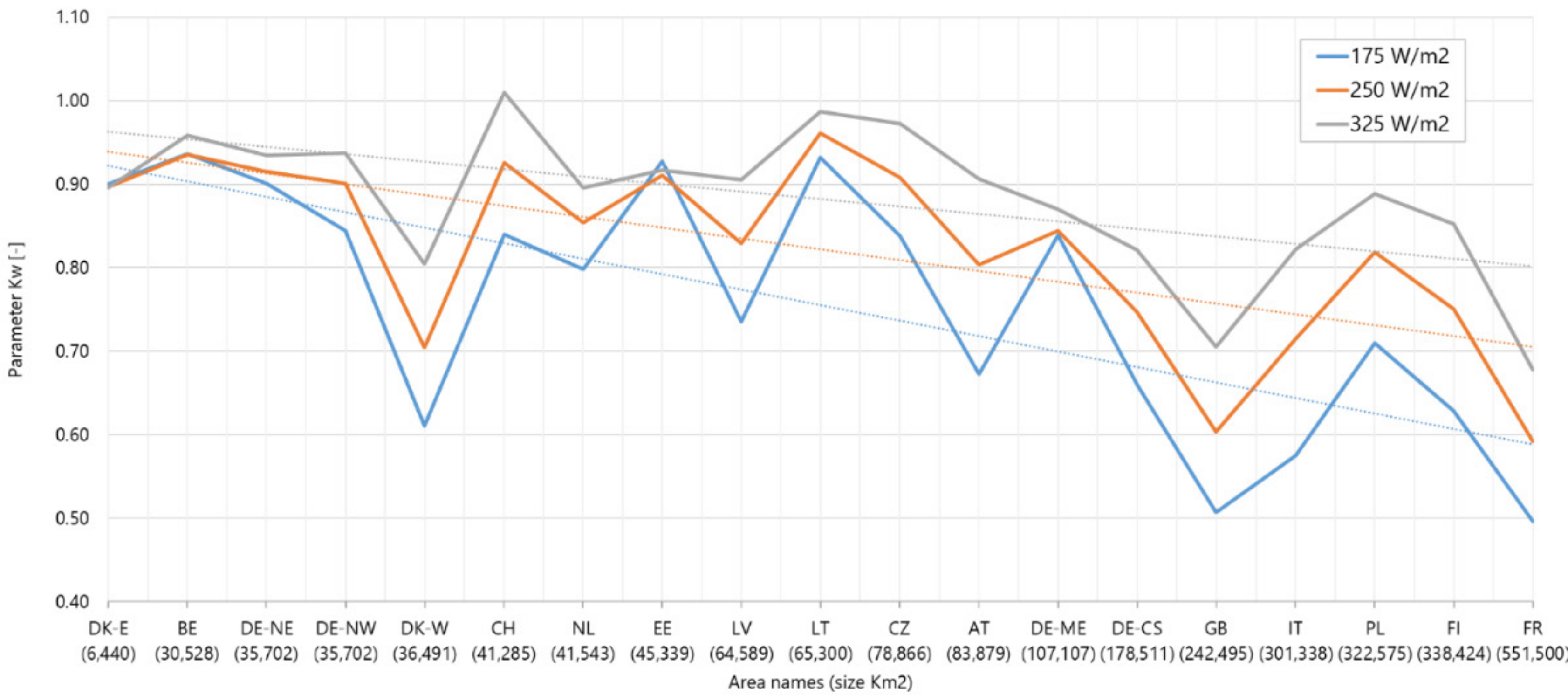

Figure A1. Smoothing factor, K_w, for the different regions