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Master of Science in Sustainable Energy
Master of Science in Electrical Energy Engineering

DTU Management Engineering
Department of Management Engineering

DIPARTIMENTO DI
INGEGNERIA INDUSTRIALE

System Value of Wind Power - An Analysis of the Effects of Wind Turbine Design

Economic dispatch modelling of medium-term system implications of advanced wind power technologies

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Summary

Nowadays, the European power system is undergoing a radical change, as the increasing share of wind energy is posing operational and market integration issues. In countries with substantial wind penetration, the simultaneous production of large wind fleets is pushing electricity prices down in hours of high wind, reducing income for wind producers. As a consequence, market value of wind is dropping, potentially endangering future investments in the technology. Beside a number of other suggested mitigation measures, deploying a more system-friendly wind technology has been proposed as an alternative and more effective solution. This advanced technology is now available in the market and features increased hub heights and larger rotor diameters for the same rated power.

This thesis intends to assess the system impacts, the potential cost reductions and the market value projections of different wind turbine designs. Using an Economic Dispatch model named Balmorel, the development of the European power system and the market outcome until 2030 is simulated. In this framework, national targets and energy policies, as well as renewables roll-out and planned transmission expansion are taken into account in the model. With a particular focus on Germany, due to the large potential for onshore wind and the country's commitment to renewable energies, the deployment of different onshore wind technologies is simulated. Five technological scenarios are assessed with different levels of specific power and hub heights. A new way of modelling wind generation using aggregated regional power curves has been specifically proposed and used for this study.

The outcomes of the analysis show that reduced specific power has a higher impact in both the system and the electricity market compared to increased hub height. Deploying lower specific power in new installations shows a decrease in total system costs and other system advantages, such as reduced curtailment, lower fossil fuel production and less steep residual load duration curve. As for the market value, large differences across specific power technologies are resulting from the simulations. The adoption of turbines with a specific power of 400 W/m^2 results in a market value of onshore wind dramatically lower than the average market price. In opposition, the reduction of specific power from 400 to 200 W/m^2 shows an increase in the market value of 30% in Germany for the year 2030, with an onshore penetration level of 31%. This figure is higher when compared to previous works considering a green-field optimum system and robust across large variations in fossil fuel and CO_2 prices. The site specific trade-off between increased levelized cost of electricity on one side and higher value on the other remains to be assessed.

The result of studies like the present one can provide policy-makers valuable information in order to design effective support schemes to drive the deployment of system-friendly wind technologies. At the same time, it could make project developers become more aware of the risks related to eventual collapse in the wind market value. Opting for economic design criteria when investing in wind power and shifting from a cost to a value perspective can have positive impacts for both private stakeholders and society as a whole.

Preface

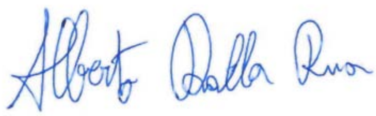
This Master Thesis was developed as a final project in fulfillment of the requirements for acquiring both the MSc in Sustainable Energy and the MSc in Electrical Energy Engineering in University of Padova, in accordance with the double degree program T.I.M.E. (Top Industrial Manager for Europe), relative to the period 2013-2016.

The master project, representing 35 ECTS, was conducted in the period spanning from the 1^{st} of February to the 1^{st} of August.

The thesis is the result of a collaboration between DTU and Ea Energy Analyses, in the framework of the work package 4 (WP4) of IEA Wind Energy Task 26 extension (2015-2018).

The main supervisor at DTU was Poul Erik Morthorst and the co-supervisor Olexandr Balyk. At Ea, Janos Hethey and Anders Kofoed-Wiuff supervised the thesis development. The supervisor at University of Padova was Arturo Lorenzoni.

Copenhagen, 1^{st} August 2016



Alberto Dalla Riva (s142176)

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Nervo. Abbiamo iniziato il nostro percorso assieme sui banchi delle superiori e ti sei sempre confermato *IL* compagno di viaggio che ognuno desidererebbe. Quante avventure assieme come un team indivisibile: calcolatrici e cervelli sincronizzati all' Universitá, zaini e cuori fianco a fianco nei mille viaggi. Senza di te non so come sarei arrivato alla fine di questo percorso. Ti tengo stretto.

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Symbols

I_{ref} Reference turbulence intensity [-]

K_w Smoothening parameter, maximum slope multiplier [-]

P_{rated} Rated power of the turbine generator [kW or MW]

V_{ave} Annual average wind speed [m/s]

V_{ref} Reference wind speed [m/s]

ΔV Absolute value gap [-]

δv Relative value gap [%]

ϵ Wind speed offset [m/s], correct theoretical output to real output

γ Maximum power output reached [p.u.]

σ Standard deviation of the wind speed distribution to be convoluted to the original power curve to smoothen it

CC_w Capacity Credit of onshore wind [%]

D Diameter of the turbine rotor [m]

M Wind speed at which the maximum growth is reached [m/s]

P Power output, correspondent to a certain wind speed u [p.u.]

g Maximum slope of the logistic curve [-]

h Height above the ground [m]

u Wind speed [m/s]

Abbreviations

AEP Annual Energy Production

CAPEX Capital Expenditures

CF Capacity Factor

ED Economic Dispatch

EEG German Renewable Energy Act

ENTSO-E European Network of Transmission System Operators for Electricity

ETS Emission Trading Scheme

EU European Union

EUA EU Emission Allowances

FLH Full load Hours

HH Hub height

IEA International Energy Agency

LCoE Levelised Cost of Electricity

LWST Low Wind Speed Turbines

MV Market Value

NEP Netzentwicklungsplan

NTC Net Transmission Capacity

O&M Operation and Maintenance Costs

OPEX Operational Expenditures

PC Power Curve

PV Photovoltaics

RES Renewable Energy Sources

RES-E Electricity Renewable Energy Sources

SP Specific Power

TSO Transmission System Operator

UC Unit Commitment

VF Value Factor

VRES Variable Renewable Energy Sources, namely wind and solar power

WEO World Energy Outlook

Others

DE-CS Central South Germany, Balmorel region

DE-ME Middle East Germany, Balmorel region

DE-NE North East Germany, Balmorel region

DE-NW North West Germany, Balmorel region

Glossary

Specific Power $[W/m^2]$

It is defined as the ratio between the rated power of the turbine in W and the swept area expressed in m^2.

$$SP = \frac{P_{rated}\ [W]}{\pi(D/2)^2} \tag{1}$$

Specific power is a crucial component in the definition of a wind technology since it affects directly the shape of the power curve and determines its production potential at the different wind speeds.

Hub height $[m]$

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

Market Value of wind [€$/MWh$]

Expressed in €/MWh is the ratio between the revenue of wind power in the market in a certain time period and its total production. 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.
Market value is sometimes also referred to as wind-weighted price and defined as follows:

$$MV_{g,z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z})}{\sum_t^T E_{t,g,z}} = \bar{p}_{g,z} \tag{2}$$

where:
t = timestep (1, ..., T)
g = technology (onshore wind, offshore wind, solar, ...)
z = market zone or country considered (DK1, DK2, Germany, ...)
T = total timesteps in the period considered (equal to 8760 if a year is considered)
E = energy production
p = market price

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 defined as the ratio between the market value in a certain market zone or country and the respective average wholesale electricity price.
The generalized expression for the value factor of a certain generation technology in a market zone is the following:

$$VF_{g,z} = \frac{\bar{p}_{g,z}}{\bar{p}_z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z}) / \sum_t^T E_{t,g,z}}{\sum_t^T p_{t,z} / T} \tag{3}$$

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

The value of wind represents the price "seen" by the wind producers in the market, with respect to average system price.

Absolute Value gap $[-]$

It represents the absolute difference in the value factors of two technologies, it is expressed with a number between 0 and 1 and is calculated as:

$$\Delta V = \mid VF_{tech1} - VF_{tech2} \mid \tag{4}$$

The higher the absolute value, the more the first technology is valuable in the market compared to the second.

Levelized Cost of Electricity $[€/MWh]$

This parameter express the cost of the MWh generated during the lifetime of the plant and it represent a life-cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}} \tag{5}$$

where:
I_0 = Overnight cost or investment cost [€]
N = Lifetime of the plant [years]
V = Variable cost [€ in year t]
E = Electricity produced in the year t [kWh in year t]
i = real interest rate [%]

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) like wind power and photovoltaics (PV) is posing some challenges to the current way power systems and power markets are operated.

In different EU countries, the share of wind power covering the demand has exceeded 15%. In Denmark, wind power has just broken its own record for the share of electricity demand covered, reaching 42% in 2015 [1]. At the same time, Germany has also seen an exponential increase in wind power, with a total installed capacity that is now around 45 GW. The *Energiewende*, the German green revolution, is placing more and more importance on the development of wind and solar in the future, making higher penetration of wind certain in the coming years. Due to its large territory and a limited access to sea, this development of wind installations will mostly come from onshore resource, which has extensive potential.

A very high wind penetration poses challenges to both operations and market functioning. Since wind power has almost zero marginal cost, it enters the supply curves in its lower part, pushing the market equilibrium toward lower prices. This effect is known as *merit-order effect* and has been described in many publications [2]. Being wind resource geographically correlated, wind farms tend to produce simultaneously, causing the so-called *self-cannibalization effect* [3]. With high wind share, wind power producers see a price in the market which is lower than the average annual price, since in the hours they are producing, wind is pushing the price down. Another effect is the increased steepness of residual load duration curve, tending to a polarization of prices: low price when a lot of wind resource is present and high prices when no wind is blowing.

The price seen by the wind producers is normally referred to as *market value of wind* or *wind-weighted price* [4] [5] and it is calculated as the ration between the total annual revenues from wind and the annual wind production.

The ratio between the *market value of wind* and the annual average price is often referred to as wind *value factor* [4] [5]. To give an idea, in 2015 the wind value factor in Germany was 0.85 [1], meaning that wind producers saw a price in the market which was 15% lower than the average one.

This reduction of the market value of wind in the system is reflected in the income of wind producers and could have implications in the future investments in the technology, potentially endangering the green transformation of the power system. The general robustness of the system with respect to prices could be influenced by this effect and the price could tend to diverge from reflecting the true value of electricity produced [4].

In the last few years, the specific power of wind turbines, expressed as ratio between electric power output and swept area, has been progressively decreasing [6] [7]. Based on the idea of higher swept areas and hub heights for the same rated power, new wind turbine design 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 the yearly Full Load Hours (FLH).

Utilizing this new concept in the power system could allow to produce more in periods of higher electricity 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 onshore wind power can potentially have large effect in the system and should not be overlooked when projecting wind development in the future [8] [9] .

1.2 Research questions

The project aims at answering the following research questions:

1. *What was the development of the wind turbine design in terms of both hub height and specific power in the last few years?*
2. *What is impact at a system level of the deployment of different turbine technologies with respect to these two parameters?*
3. *How could different turbine designs affect the value of wind in the power system in the next 15 years?*

1.3 Previous studies and contribution of this work

In the last few years, with the aforementioned increased penetration of wind power in terms of power demand coverage, more and more attention has been placed on the market value of wind in the power system. This is particularly true for countries like Denmark, Germany and to some extent the U.S.

Many publications focused on the value of wind and on its future development under different system conditions. In Germany, for example, the topic was the focus of different papers [4], [5], [10], [11] and reports [12], [13]. In Denmark a detailed analysis of possible measures to increase the value of wind was carried on by EA Energy Analyses [14]. Finally, in the U.S., California has been used as a test case by [15] and [16]. A common result of these analysis is underlying how an increased penetration of wind results in a marked drop in its market value. The feature of these studies is a focus on different integration measures, in order to reduce this value drop in future systems.

On the other hand, the impact of the turbine design and the technology trends on the value of wind is a recent topic and a research gap is present. Only few studies are currently available to the author's knowledge. A work by Nils Günter May [17] has focused on the effect of support schemes on the technology choice, while another study recently published by Simon Müller and Lion Hirth [8] has described the market effects of different technology choices. The main result of the latter is that advanced turbine design in term of specific power and hub height can largely reduce the wind value drop at high penetration level. Moreover, designing wind turbines in a more system-friendly way performs better than other integration measures in limiting the aforementioned drop. The main finding from the study is shown in Figure 1.1, where the value drop is compared for classical and advanced turbine design.

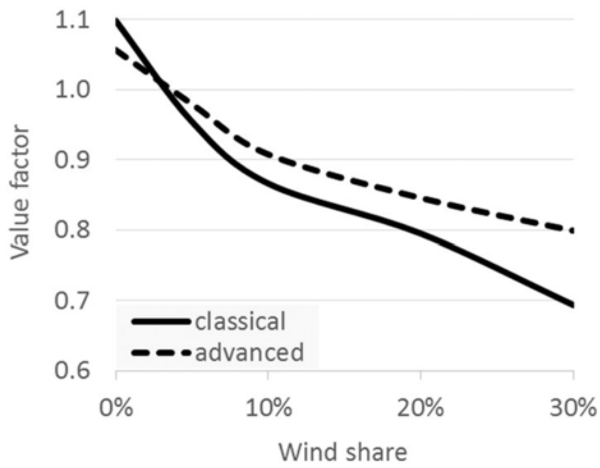


Figure 1.1: Advanced turbine design reduces the wind value drop. At 30% penetration rate the drop is reduced by 11%. Source: [8]

Given the theoretical result just presented, the aim of this study is to evaluate the value of improved design in a different framework. The focus is placed on future years up to 2030, where the policy conditions, RES roll-out and other limitations to the system development will be fixed exogenously, based on national and European plans, as well as current regulation.

The main idea is having a "policy-maker" and medium-term perspective rather than simulating different penetration levels where the system can adapt by investing in any technology (long-term perspective). Moreover, both existing wind fleet and future onshore technologies will be modelled, giving the possibility to assess how the marginal future wind installations can affect the value of wind.

Another objective of this work is to understand and improve the modelling of wind generation in an economic-dispatch model with large geographic scope and detailed description of heat and power sector as Balmorel. Being an open source model, this contribution can hopefully be helpful for present and future energy system studies. The modelling of wind power production is based on wind speed time series and regionally aggregated power curves.

To sum up, the specific contribution of this work compared to previous studies is related to:

- Market value of wind in a broad geographical perspective
- Contribution from specific power and hub height assessed separately
- Policy makers approach, i.e. modelling based on existing system and planned development (exogenous parameters)
- Focus on future years, rather then a more theoretical approach based on wind penetration levels
- Marginal effect of future technology, taking into account historical installed capacity
- Insight into wind production modelling in an economic-dispatch model, including the effect of aggregation of power curves at a region level

1.4 Thesis outline

The Thesis is divided into four major parts: Background, Modelling, Results & Discussion and Conclusion.

The *Background* includes a general perspective on RES and wind development, a description of the day-ahead market and how wind power interacts with it, and an anaysis of onshore wind technological development.

The *Modelling* part presents the Energy system approach with a description of the model used, the modelling of wind production and the scenarios chosen.

Under *Results & Sensitivity*, the outcome of the simulations is presented with a critical analysis of the different results.

Finally, the most important considerations and remarks are drawn in *Discussion & Conclusions*, together with suggestions for further studies.

Guideline For a proper understanding of the thesis, the most important Chapters and Sections are the following: definitions in Section 3.4, 3.5 and 4.2, technological development described in 4.4, Chapter 5 describing the main idea of lower specific power and the first three sections of Chapter 7 specifying the analysis framework and the scenarios. Chapter 9 is fundamental for the results, followed by Discussion (Chapter 11) and Conclusion (Chapter 12).

Part I

Background

2

Renewable energy trends

2.1 RES development in Europe

Over the last decade, global deployment of RES-E, especially wind and solar, has grown tremendously. Europe has always been at the forefront of this transformation of the power system based on renewable energy. In order to increase the penetration in the energy mix, a variety of subsidy schemes and dedicated regulation has been put in place by the majority of the countries and by the European Union itself.

The advantages of such a transformation are various: economic competitiveness, technological innovation in industry, diversification of power mix and reduction of foreign dependency, climate change mitigation and pollution reduction, growth of local economy [18]. Among the measures adopted by EU, the Renewable Energy Directive of 2009 set binding targets for all member states, in order to reach a 20% share of energy from RES [19]. Recently, a new target for 2030 has been agreed upon to ensure renewables will keep playing a key role in the future. Specifically, the objective is achieving at least 27% share of RES energy consumption and 27% energy savings compared to Business-as-Usual scenario [20].

This commitment and the development of cost-effective RES technology guaranteed in the past 10 years a flourishing environment for investments, which resulted in an exponential growth at a European level, enough to reach almost 500 GW of RES installed capacity at the end of 2015 (215 GW hydro, 145 GW wind, 100 GW solar, 40 GW bioenergy and others) [21].

2.2 Role of wind power in the European targets

Due to its cost-competitiveness, large potential and relatively advanced technological maturity, wind power has been the biggest contributor to RES-E development. In fact, wind power installed more than any other form of power generation in 2015 and it accounted for 44.2% of total 2015 power capacity installations in Europe [22]. The drivers for this success are various: subsidies in different European countries, innovation in the industry, learning curve impact and economy of scale.

A distinction between onshore and offshore wind has to be made. Indeed, while the former has gained a certain level of technological and market maturity reaching a very low levelised cost of electricity (LCoE), the latter still suffers from a very high capital cost mainly related to foundations and installation, and has so far seen a major deployment only in Europe. The focus of the offshore industry is now bringing down costs and make the technology more economically viable. On the other hand, different studies confirm that onshore wind already became the cheapest source of energy in different countries, having potentially lower LCoE than coal and gas [23] [24].

The current level of installed capacity in Europe is 142 GW, 92% of which is onshore and 8% offshore. The distribution in the 28 EU countries is shown in Figure 2.1.

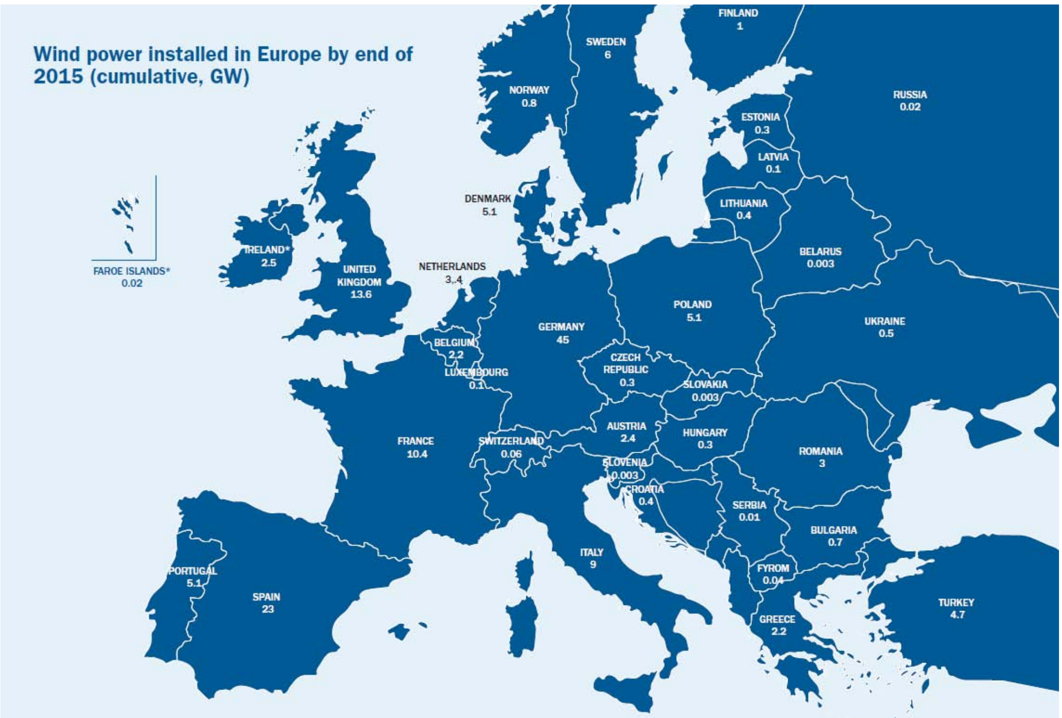


Figure 2.1: Wind power installations per country in GW. Source: [22]

With the capacity installed at a European level, in a normal meteorological year wind power is enough to produce 315 TWh and cover 11.4 % of EU's total electricity consumption [22]. In several countries, the share of annual consumption covered by wind power in 2015 has reached notable values such as in Denmark (43%), Ireland (24%), Portugal (23%), Spain (18%) and Germany (14.5%) [25].

The European Wind Energy Association, in their 2030 Scenarios, expects between 251 and 392 GW of wind power, depending on the scenario. In the High Scenario, a production up to almost 1,000 TWh would be able to provide 31% of EU electricity demand [26].

2.3 Renewable energy in Germany

Energiewende

Leading the scene in Europe, German energy sector is being characterized by a radical conversion. The so called *Energiewende* is an ambitious plan of green transformation based on energy efficiency and renewable sources. Moreover, after Fukushima accident, the nuclear sector is being decommissioned and the country is working even more toward renewable energy development.
The main objectives of the *Energiewende* are [27]:

- Fighting climate change
- Reducing energy inports
- Stimulating technological development and innovation
- Increasing energy security
- Strengthening local economies

The base for this development has been set by Germany's Renewable Energy Acts (EEGs), regularly amended and updated, which provide incentive schemes tailored for the development of each renewable source. Initially this compensation enabled to fully cover the cost of RES installations, through feed-in tariffs and guaranteed purchase (EEG 2000). At a later stage, in particular thanks to EEG 2012, an encouragement to direct marketing was promoted thanks to the switch to feed-in premiums. Finally, with EEG 2014 and 2016, a switch to auction-based incentives has taken place [28].

The official national goal sets by EEG 2014 is a renewable share in the power sector of 40-45% by 2025, 55-60% by 2035 and an ambitious level of 80% by 2050 [28].

Figure 2.2 shows the development of RES-E capacity in Germany in the last 14 years. As it is possible to note, solar and wind power are the main contributors and the growth of these two sources is not projected to stop, especially due to the large potential of the country, the cost reduction and the political support.

As shown in Figure 2.3, in 2015, 30% of the gross electricity production was supplied with renewables. In particular, 13.3% came from wind power, 6 % from PV and almost 7% from biomass.

Wind Power

As shown in Figure 2.1, Germany is the European leader in terms of wind capacity installed, with a level of 45 GW at the end of 2015.

To achieve the ambitious target of 80% RES in the power sector by 2050, the German government has specified an amount of 2.5 GW of newly installed onshore wind capacity annually over the next years [17].
The wind capacity addition in the last two years has been massive: 5.2 GW installed in 2014 and more than 6 GW in 2015 [22]. Taking this into account the aforementioned annual target seems more than reasonable.

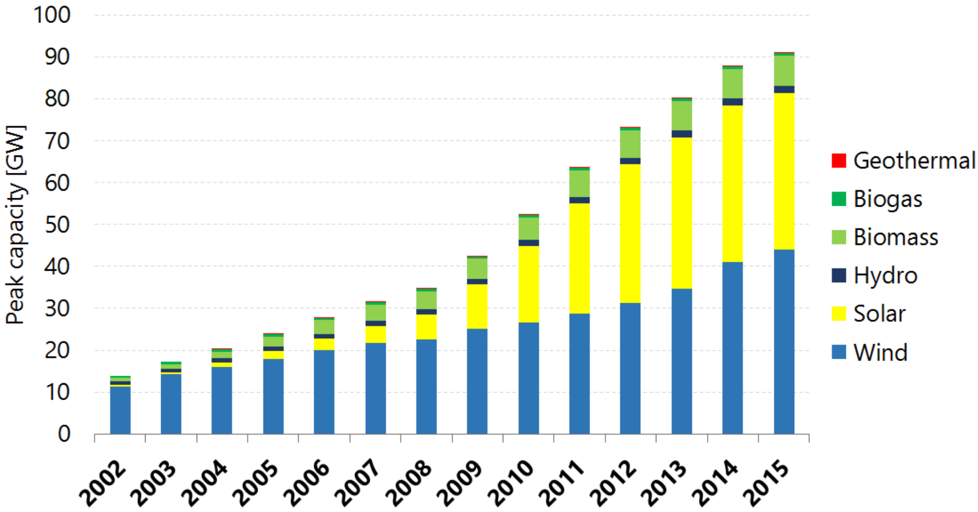


Figure 2.2: RES Capacity in Germany. Elaboration of data from [29]

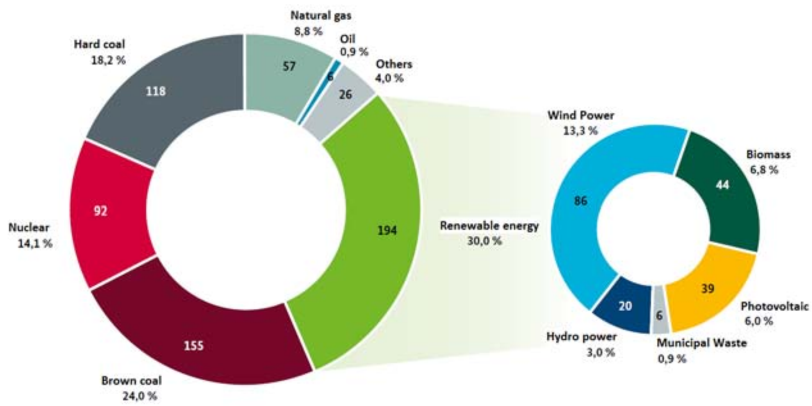


Figure 2.3: Gross electricity production in Germany in 2015 by energy source. Translation of figure from [28]

An analysis of different government estimates in [5] projects a value for the total wind generation of about 18% of the electricity demand in the country in 2019, of which 14% coming from onshore wind and 4% from offshore.

The predominance of onshore wind depends on different factors. First of all, it is due to the higher LCoE and the nascent stage of offshore technology already mentioned. Moreover, the central position of Germany in Europe and its limited access to sea results in a cap to the offshore potential. Finally, the German offshore planning sites are characterized by great distance to shore and water depths, increasing costs and technological efforts [5]. Given this, it is clear that the main contributor to wind development in the coming years in Germany will be onshore wind. Moreover, considering that to date most of the turbines are placed in the north-west region where wind resource is better, an increased importance of medium and low wind sites is foreseeable in the future.

3

Wind and electricity markets

3.1 Day ahead market - EPEX SPOT

Electricity is a commodity that is normally traded between different parties, in a number of dedicated markets. Existing power markets are organized with very different time horizons and scope as shown in Figure 3.1. Beside those represented, an alternative way of trading power is through bilateral contracts, also called over-the-counter (OTC).

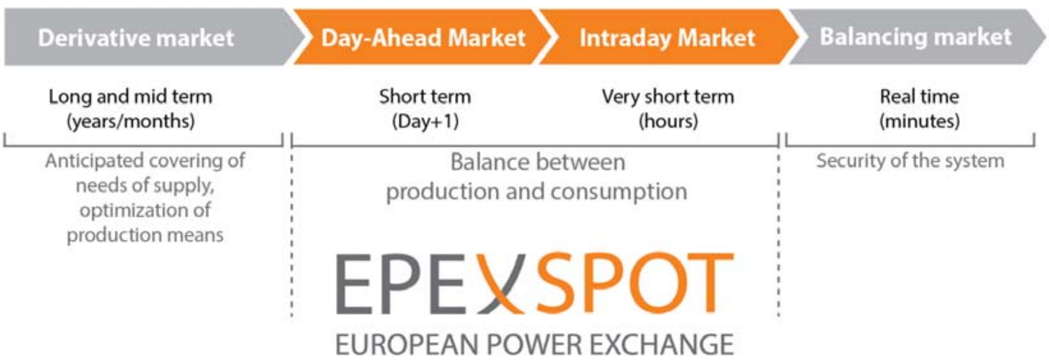


Figure 3.1: Different power markets and relative time horizons. Source: [30]

The **day-ahead market** or spot market is typically the one characterized by the highest volume traded. It is an auction where power is traded for delivery during the next day. Exchange of electricity throughout the day d is organized in an auction cleared at day $d-1$, where producers submit energy blocks together with the minimum selling prices for each hour of the day d. The exact same procedure is carried out by the consumers, who submit 24 electricity blocks with their corresponding purchase prices.
Producers submit their offers at the minimum selling price (willingness-to-accept), while consumers submit their consumption bids at the maximum buying prices (willingness-to-pay).

After the closing time, at 12:00 CET of the day $d-1$, equilibrium between the aggregated supply and demand curves is established for all bidding areas and for each hour of day d.
The outcome of the market in the resultant equilibrium point is a certain volume traded and a market price. A visualization of the equilibrium at the intersection of demand and supply curve is shown in Figure 3.2.

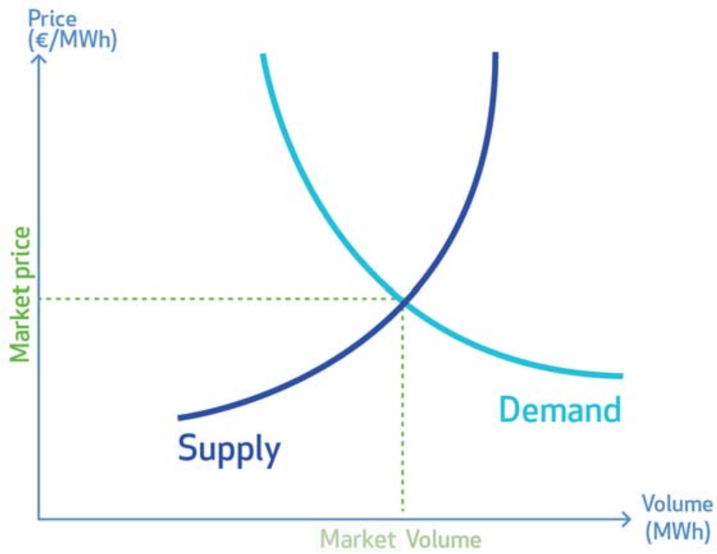


Figure 3.2: Clearing mechanism in the day-ahead market. Source: [31]

EPEX SPOT is the exchange for the power spot markets of Germany, France, Austria and Switzerland. It is linked to the other major European day-ahead markets thanks to a market coupling mechanism, forming a multi-regional market area which now covers 19 countries and about 85 % of the European power consumption.
Market coupling is a tool to manage congestions on the borders between different markets, which optimizes the allocation of cross-border capacities thanks to a coordinated calculation of prices and power flows [30].

An important characteristics of EPEX SPOT, e.g. compared to Nord Pool (the correspondant of EPEX for the Nordic Countries), is the low portion of load traded in the day ahead market. Even though the market volume of EPEX is currently increasing, the share traded in 2013 was equal to 39% (in Nord Pool it was about 85%), while the rest of the production was traded via bilateral contracts [32].

3.2 Impact of wind in the day ahead market

When adding wind and, more generally variable RES, in the power mix, the resultant market price is affected. Large capacity of wind in the system has the effect of reducing the wholesale spot price, due to the so-called **merit-order effect** [2].

The basic idea behind the merit-order effect is that wind has low marginal cost due to the absence of fuel cost, therefore it is entering the supply curve in its lower

part, with the effect of shifting it to the right. A shift of the supply curve to the right results in a lower equilibrium price, since expensive generators that were first dispatched are pushed out of the market and substituted by wind.
The magnitude of the shift depends on the capacity of wind installed and the resource availability at the specific time. It reaches its maximum when the wind resource is high [2]. A visualization of the merit order effect is given in Figure 3.3.

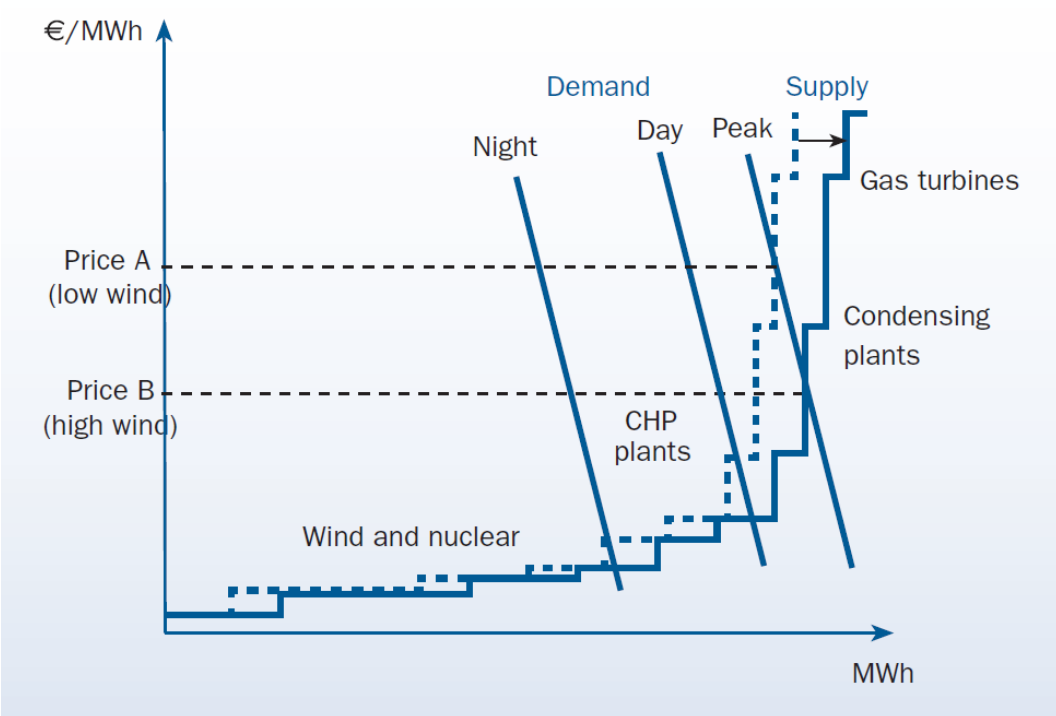


Figure 3.3: Merit order effect at different demand levels. Source: [2]

An important factor is that demand is inelastic due to the necessity nature of power in modern society. As a result, change in the supply can cause large changes in price without the possibility for the demand to react. Moreover, due to the typical structure of supply curve, the merit-order effect have different impacts at different demand level.
As can be seen, in correspondence to demand peaks the merit order effect is considerable, due to the steepness of supply curve. On the contrary, at hours of low demand (e.g. night) equilibrium is found in a more flat part of the supply curve, resulting in a lower price change [2].

The final result is lower electricity prices when wind is blowing and, in general, lower average prices in a system with high wind penetration.
The merit-order effect and its influence on spot prices has been demonstrated both through model simulations and trough regression analysis of market data for different countries. A review of different studies can be found in [2] and an updated list of publications regarding the topic is listed in [33].

This effect causes a negative correlation between hourly wind production and hourly

wholesale power prices in systems with high wind penetration.
In [34] a clear example is shown for Germany in the year 2015, during which the wind contribution to power demand in the country was equal to 13.3%. Figure 3.4 shows the electricity price expressed in øre/kWh (Danish currency) with respect to the wind production, in bins of 2000 hours.
Even though price is strongly dependent on demand and a lot of other mechanisms contribute to the price formation, this is a clear evidence of how wind is driving electricity prices down.

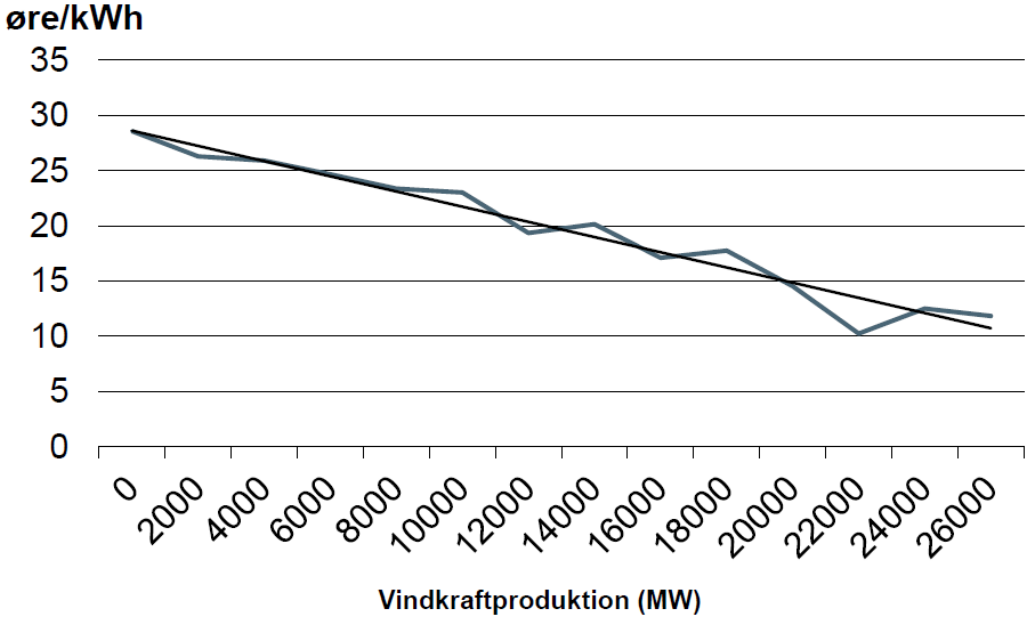


Figure 3.4: Correlation between wind production and average electricity price in Germany (grey) during the year 2015 and correspondent linear fit (black). Source: [34]

3.3 Levelized Cost of Electricity

One metric to characterize the generating technologies in a power system, by ranking them with respect to generation cost, is the **Levelized Cost of Electricity** (LCoE). This parameter express the cost of the MWh generated during the lifetime of the plant and it represent a life-cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}} \tag{3.1}$$

where:
I_0 = Overnight cost or investment cost [€]
N = Lifetime of the plant [years]
V = Variable cost [€ in year t]
E = Electricity produced in the year t [kWh in year t]
i = real interest rate [%]

Since it includes investment and fixed O&M, it represents also the long-run marginal cost of the generating technology.

While it is important to take into account the cost of the MWh during the lifetime, it cannot represent the only metric for comparing different technologies, since it lacks other important information on the economic value of the technology. Indeed, as shown in [35], LCoE is a flawed metric when analysing the value of intermittent technologies such as wind and solar. In particular, it fails to take into account the interaction with the day-ahead market in terms of time of production and realized prices.
A new perspective has been proposed, based on an LCoE which includes integration costs, called **System LCoE** [36]. The main idea is adding to the typical generation costs described by the LCoE, other costs related to the integration of the technology in the power system, such as balancing, grid and profile costs. While this new metric captures the effects of variable RES production, the different cost components difficult to estimate and it is still not universally accepted an used.

3.4 Market Value of Wind

In order to have a more complete picture of the system and market interaction of wind power, it is important to switch from a purely cost-focus perspective, typical of LCoE metric, to a value perspective. In particular, due to the interaction with the market described in the previous sections, the focus should be placed on 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 publications and studies.

Following the classical definition, e.g. 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 total production. 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 and defined as follows:

$$MV_{g,z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z})}{\sum_t^T E_{t,g,z}} = \bar{p}_{g,z} \tag{3.2}$$

where:
t = timestep (1, ..., T)
g = technology (onshore wind, offshore wind, solar, ...)
z = market zone or country considered (DK1, DK2, Germany, ...)
T = total timesteps in the period considered (equal to 8760 if a year is considered)
E = energy production
p = market price

For a clearer picture and for ease of comparison, market value is usually expressed in relative terms, with respect to average day-ahead market price (time-weighted).
The **Wind Value Factor** is defined as the ratio between the market value in a certain market zone and the average price of that zone.
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 generalized expression for the value factor of a certain generation technology in a market zone is the following:

$$VF_{g,z} = \frac{\bar{p}_{g,z}}{\bar{p}_z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z}) / \sum_t^T E_{t,g,z}}{\sum_t^T p_{t,z}/T} \tag{3.3}$$

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

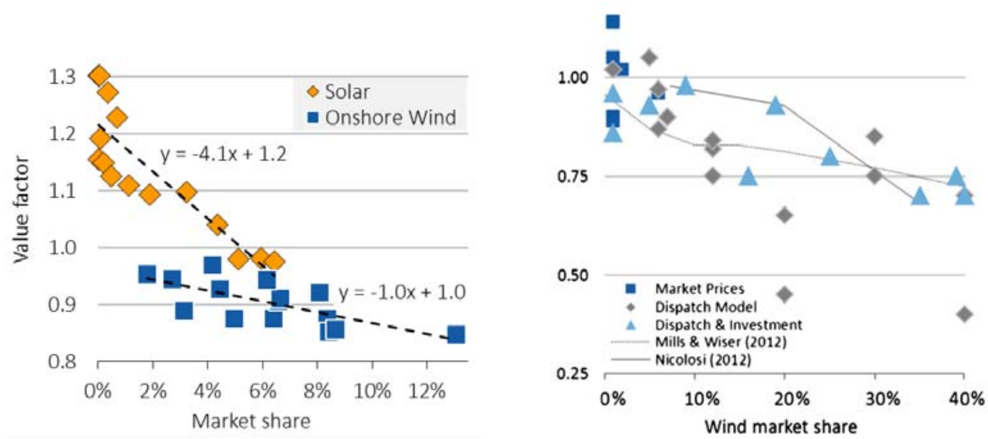
The value of wind represents the price "seen" by the wind producers in the market, with respect to average system price. By focusing only on the market component of the wind producers revenue, it excludes incomes from any support scheme potentially in place.

When making investment decisions for merchant generation expansions, investors compute both long-run marginal cost (LCoE) and future prices at which the output of the plant can be sold [37]. In the case of wind, future marginal costs are easier to forecast since no fuel is used for the production, while all the uncertainty lays in the market outcome for the lifetime of the plant.
For this reason, the value of wind plays a crucial role for investment decisions in wind power and the future development of wind installation could depend on the value of wind at higher penetration rates.

The market value can be expressed for wind power as a whole or, alternatively for offshore or onshore wind separately, following the same definition as above, but considering only the respective production $E_{t,g,z}$.

3.5 Statistics on the Value Factor

An extensive analysis of historical market data and literature studies on the topic has been carried out in [4]. As mentioned, market value is projected to decrease with the increase of wind penetration in the future.
When looking at historical data, a clear sign of this tendency can be found. Figure 3.5(a) shows realized VFs for onshore wind (and solar) in Germany for different penetration levels of onshore wind in the period 2001-2015, while Figure 3.5(b) shows the results of various studies on the topic, mainly using dispatch models, around the world.
The value of wind in Germany in 2015 was 0.85 with a wind penetration of 13.3%.



(a) Historical (b) Literature review

Figure 3.5: Development of VF at different penetration levels (market shares), realized in Germany **(a)** and from literature studies in various power systems **(b)**. Sources: [4] [38]

Elaborating data from [1], similar results for Denmark can be observed in Figure 3.6. In 2015, with a wind penetration of 42%, the value factor was equal to 0.85.

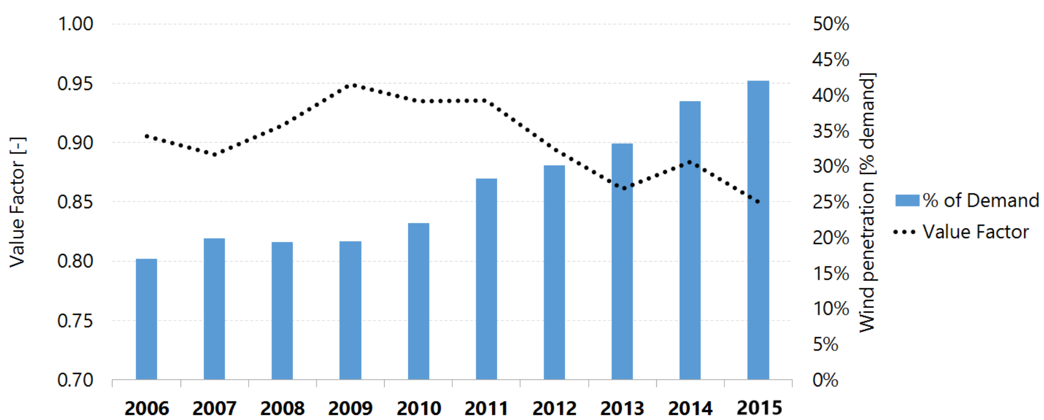


Figure 3.6: Development of VF and wind penetration over time in Denmark. Elaboration of data from [1]

The level of VF is the same as Germany, with a 29% higher wind penetration. Indeed, Denmark is a well interconnected country, where a lot of measures aimed at wind integration has been put in place. However, the main reason for this mismatch is related to the availability of hydro power, thanks to the large connection to Norway and Sweden, which help mitigating the value drop [38].

The relation between VF and wind penetration for Denmark is shown in Figure 3.7.

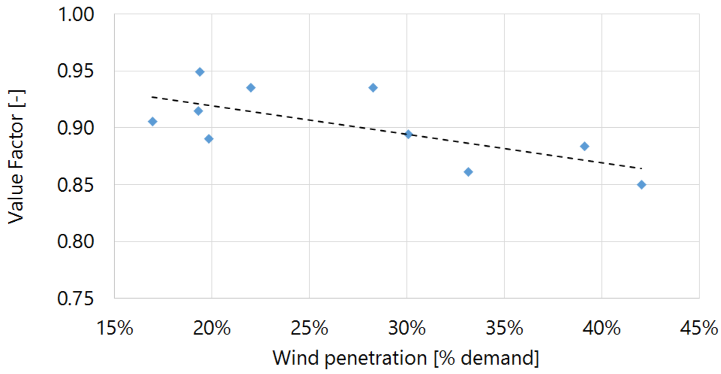


Figure 3.7: Relation between value factors and wind penetration in Denmark in the period 2006-2015. Elaboration of data from [1]

4

Onshore wind and the Silent Revolution

4.1 Wind power curve

A wind turbine is a power generation technology which transforms the kinetic energy of the incoming wind into electrical energy.
The output of a wind turbine depends on several factors, as explained in the following equation:

$$P_T = P_W \cdot C_p = \frac{1}{2} \cdot \rho \cdot A \cdot u^3 \cdot C_p \tag{4.1}$$

where ρ is the air density, A the swept area and u the wind speed at hub height. The power coefficient C_p is the ratio of power extracted by the turbine and the total contained in the wind resource: $C_p = P_T/P_W$. Therefore, it represents how well the turbine turns the power in the wind into mechanical power.
The power coefficient varies at different wind speeds and the maximum physical value is 0.59, called the Betz limit.

The relation between the wind speed of the incoming wind and the power which the turbine is able to produce is described by the so-called **Power Curve** (PC) of the turbine. An example of a power curve from a 2.5 MW horizontal-axis turbine is shown in Figure 4.1.
The parameters which define the power curves are rated power, cut-in speed, rated speed and cut-off speed. The rated power is the maximum power output of the turbines and is dependent on the generator chosen for the turbine. The cut-in speed represents the wind speed after which the turbine starts producing power. At rated speed, the turbine output reaches the rated power and from this speed on, the power is kept at the rated level until the turbine is shut down at cut off-speed. This is done for safety reasons, in order to avoid potential damages to the blade and the structure at very high wind speeds (storms). It is possible to identify different functioning areas depending on the wind speed in input:

- Area A, the turbine is not producing due to the very low wind speeds;
- Area B, the turbine produces at variable C_p and the relation with the wind speed is cubic;

- Area C, the turbine is producing at constant power output by reducing its aerodynamic performances;
- Area D, no power is produced.

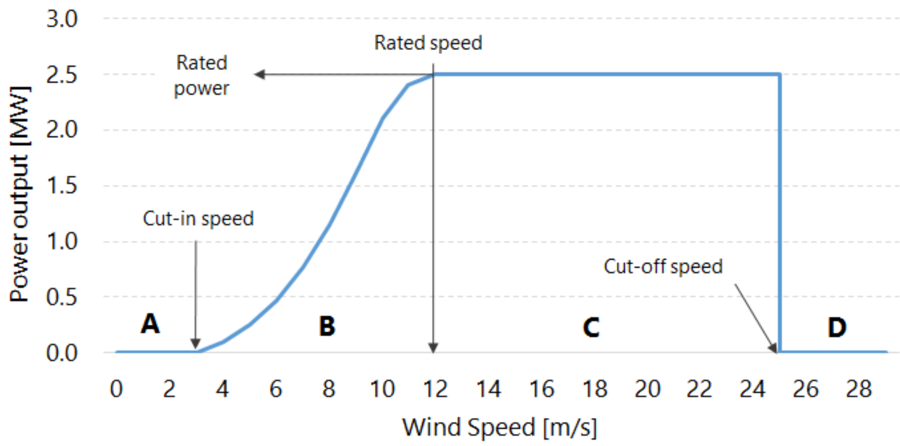


Figure 4.1: Typical power curve of a 2.5 MW horizontal-axis turbine

4.2 Relevant parameters for the analysis

In this study, the parameters considered to define the design of a wind turbine are the Hub Height (HH) and the Specific Power (SP).

Hub Height In an horizontal-axis wind turbine, it represent the distance of the rotor shaft from the turbine platform and describes how high the turbine stands above the ground.
This parameter does not affect directly the shape of the power curve, but it influence the wind resource seen by the turbine. Since the wind speed increases with height, the higher this parameter is, the higher is the incoming wind speed at the turbine rotor.

Specific Power It is defined as the ratio between the rated power of the turbine in W and the swept area expressed in m^2.

$$SP = \frac{P_{rated}\ [W]}{\pi(D/2)^2} \tag{4.2}$$

The same concept is sometimes referred to as Specific Area instead, which is the reciprocal of the specific power and is expressed in m^2/kW. As an example, a specific power of 200 W/m^2 corresponds to a specific area of 5 m^2/kW.

$$SA = \frac{1000}{SP} = 1000 \cdot \frac{\pi(D/2)^2}{P_{rated}\ [W]} \tag{4.3}$$

Specific power is a crucial component in the definition of a wind technology since it affects directly the shape of the power curve and determines its production potential at the different wind speeds.

4.3 Wind classes

IEC 61400-1 [39] determines a standard for design requirements of wind turbines. The latest edition (Ed.3 and amendments) describes different wind turbine classes, defined based on two basic parameters: reference speed and turbulence intensity.
It has to be noted that, unlike most wind-engineering standards, IEC 61400-1 does not try to predict local wind conditions, but instead classifies turbines based on a range of load cases. Consequently, it is the project developer to ensure that site conditions are less severe than defined by the specific class of the turbine used [40].

Each class is defined by a number (I, II, III) which indicates the reference speed and a letter (A, B) for the turbulence intensity. An additional class, IEC class S, includes turbines for which the values are specified by the manufacturer and it is normally used for offshore turbines.

The annual average wind speed for turbine design according to these classes, can be calculated based on the following formula:

$$V_{ave} = 0.2 \cdot V_{ref} \tag{4.4}$$

Table 4.1 shows the different wind classes and the related parameters:

Wind turbine class		**I**	**II**	**III**	**S**
Annual average wind speed [m/s]		10	8.5	7.5	Values
Reference speed V_{ref} [m/s]		50	42.5	37.5	specified
	A	0.16	0.16	0.16	by the
Turbulence I_{ref} [-]	**B**	0.14	0.14	0.14	manufacturer
	C	0.12	0.12	0.12	

Table 4.1: Parameters for the different turbine classes, IEC 61400-1. Source: [39]

4.4 Onshore wind turbine technology trends

The horizontal-axis wind turbine technology, contrary to what it may seem at first glance, is in constant evolution.
Some global macro trends can be identified in the continuous growth of rated power, rotor size and hub height over time [41]. Moreover, the drive train and the control system have been stabilizing toward some specific designs [42]. Nonetheless, there is something more subtle happening in the wind industry, which has been described as *Silent revolution.*

The Silent Revolution This term has been used by Bernard Chabot in a series of articles and analysis, to describe the transformation happening in the onshore wind industry in the last few years [9], [6].

With part of the best wind spots already taken, producers started to design new turbines, suitable for low wind speed areas.

Most of the wind manufacturers currently produce or have announced their own models optimized for lower wind sites and generally classified as IEC Class IIIA. In order to increase the production and consequently boost the capacity factors (CF), the specific power of these models is reduced. Indeed, the power being constant, a higher swept area enables to harvest more power at low wind speeds.

The specific power of LWST is now down to less than 200 W/m^2, resulting in potential annual full load hours up to more than 4000, a level unimaginable until some years ago.
Following this idea of higher energy yields, the specific power of installed turbines has been dropping significantly, thanks to LWST installations but also a general reduction in specific power for turbines in high wind sites as well. In general, the growth in rotor diameter has outpaced the one in rated capacity of turbines [41].

In the U.S. this trend is quite substantial, with very low specific power turbines in the range 190-220 W/m^2 gaining around 50 % of the market both in 2013 and 2014. The drop of specific power for recent installation in the U.S. is shown in Figure 4.2. Another sign of the transformation is the share of Class III turbines installed: in 2014, only 6% of the turbines installed were class II or lower, while 94% of them were Class III or II/III (intermediate characteristics).
To sum up, not only the market shifted to higher IEC classes, but also the specific power of class II and III has diminished over time [7].

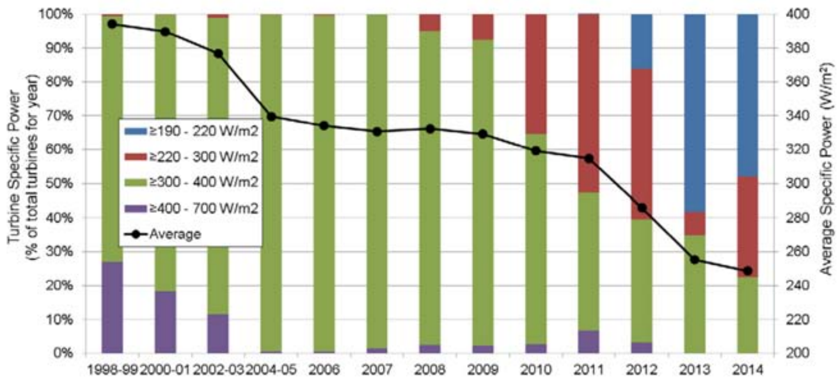


Figure 4.2: Specific power development in U.S. over time. Source: [7]

An analysis of the data from the new German Renewable Power Plants register [43] by Bernard Chabot [44] shows that Germany is also shifting to lower specific power turbines. A clear acceleration in the rate of decrease of specific power in the last couple of years compared to historical values is underlined. Moreover, since the SP for approved projects are lower than for commissioned ones, a supplementary decrease can be expected.

On the other hand, the level of specific power for this recently commissioned and approved onshore turbine is still higher compared to the level reached in the United States.
Figure 4.3 shows the distribution of specific power for approved and commissioned projects in 2014 and 2015, which average was 360 W/m^2.

These results confirm that in Germany there is room for a further decrease of specific power.

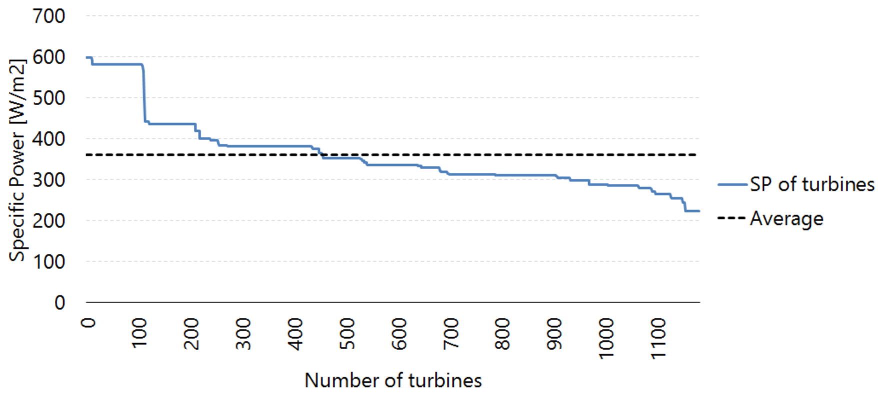


Figure 4.3: Specific Power for each approved or commissioned onshore project in Germany above 800 kW, showed in decreasing order. Elaboration of data from [43]

Hub height Globally, hub height of turbines has been continuously increasing due to better materials deployed and improved design of the towers. The main driver has been the higher wind resource available.

In Germany, this trend has been even more acute with newly announced models reaching 159 m of hub heights (Enercon E-141 EP4 [45]). Among new installations, the average hub height in 2015 was 121 m [46], as it can be seen in Figure 4.4.

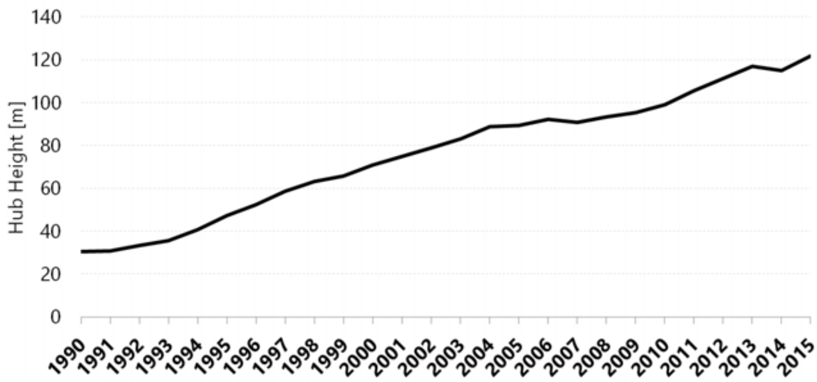


Figure 4.4: Hub height trend for new installations in Germany. Source: data from [46]

An analysis of the data from the new German Renewable Power Plants register [43] shows that among the approved and commissioned projects above 800 kW in the last 2 years, a considerable amount of projects feature heights of 140 m or more (Figure 4.5).

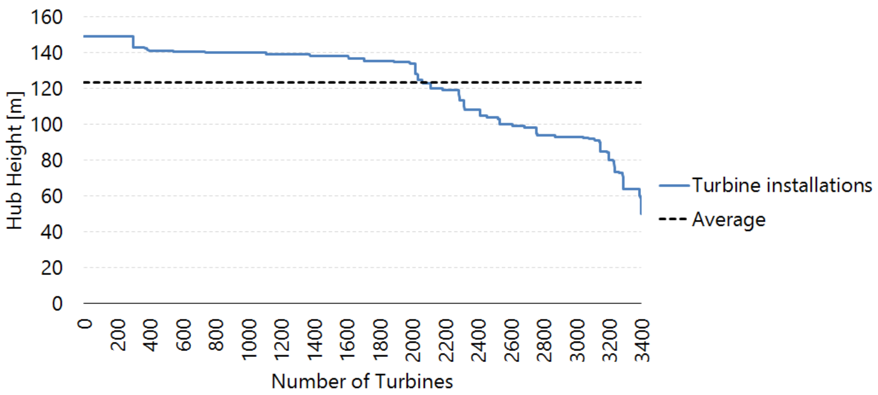


Figure 4.5: Hub height for each approved or commissioned onshore project in Germany above 800 kW, showed in decreasing order. Elaboration of data from [43]

4.5 Low wind speed turbines

In Table 4.2 the latest onshore models for IEC class IIIA are shown with their specifications, ranked from the lowest to the highest specific power. Where possible, information regarding available hub heights and rated wind speed was added. It has to be noted that some models are designed for sites with lower turbulence intensity and therefore certified for IEC class IIIB.
The specifications are collected from manifaturers websites and online databases [47], [48] and [49].

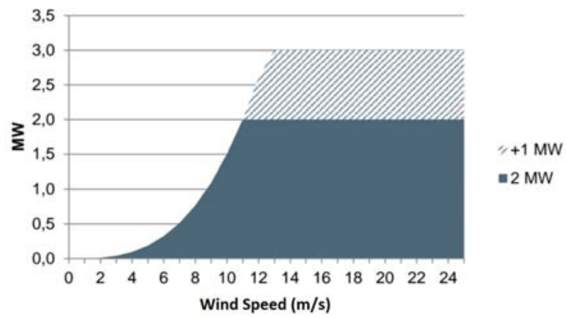
4.6 Low specific power for higher IEC classes as well?

All LWST models described above are originally designed for low wind speed sites, corresponding to IEC Class III requirements. This results in strong limitations in terms of suitable sites for its deployment. Nevertheless in the U.S., where the Class III turbines makes up already the vast majority of new installations, LWST are now in widespread use in high wind sites as well [7]. Similarly, a general reduction of SP across all IEC classes is expected in the future by [50].

Following the general reduction in specific power occurred in the last few years, it is foreseeable that turbine models with a specific power in the range $200 - 250\ W/m^2$ will be available for IEC classes I and II as well. This reduction of SP is practicably reachable in three ways:

- Increasing the swept area: thanks to future improvements in blade and structure design, the limit of swept area for Class I sites can be pushed forward;
- Decreasing the rated power of the generator: this could be an economically viable option when the value drop is significant. Indeed, at hours of high wind production, the self-cannibalization effect would largely reduce the price, making the savings from a smaller generator more attractive.
- Combining the previous two measures

Some analysis of how reducing generator size could be relevant in the future has been carried on by Dansk Energi and showed in Figure 4.6.



(a)

	Turbine 1	Turbine 2	Last MW
Capacity (MW)	2	3	+1
Rotor diameter (m)	100	100	0
Production (MWh)	6000	7000	+1000
Full load hours (h)	3000	2300	1000
Price gap (øre/kWh)	2	2.6	6

(b)

Figure 4.6: Difference between market price and market value of wind for a turbine of 2 MW, 3 MW and value seen by the last MW. Source: translation of [51]

The main idea is that in a future energy system with more and more wind power, the price that turbines sees in the market when the last MW is producing, is much lower than the average price and lower than the one seen by the entire turbine. It will soon make sense to reduce the rating of such turbines. Indeed, on the one hand the total energy production in the site is reduced (the extra-production takes place in hours with low price), but on the other hand savings on the generator and electrical equipment cost, reduction of the weight in the nacelle and lower grid connection costs can be expected. The result of such a trade-off could influence the design of new turbines, reducing SP in high wind sites.

As a result of what just presented, in this study wind turbine design in terms of SP and HH will be applied regardless of the IEC class. In other words, when applying a low specific power turbine, there will be no limitations to where it can be installed based on the resource characteristics of the site.

As for offshore wind, due to the better wind resource and the generally higher towers, the specific power is not projected to diminish at the same pace as onshore wind. Nonetheless, some studies [52] [53] assessed the economic benefit of the so-called overplanting, i.e. increase the number of turbines in an offshore wind park without increasing the rated power of the cable to shore. The positive effect of this measure is related both to savings in the export cable investment and an increased specific power of the park as a whole, resulting in higher production at low wind speeds and less volatile output from the park. On the other hand, excess power will lead to a curtailed production at higher wind speeds. Since onshore wind is the focus of this work, the possibility of overplanting will not be considered and no options to reduce the specific power of offshore wind will be taken into account.

Model	Rated power [MW]	Rotor diameter [m^2]	Specific Power [W/m^2]	Hub heights m	Rated wind speed [m/s]	Reference
Below 2.5 MW						
GE 2.0-116	2	116	**189**	80/94	10	[49]
Gamesa G114	2	114	**195**	93/120/140*	10	[48]
Gamesa G126	2.5	126	**200**	84 to 129	10	[47]
Siemens 2.3-120	2.3	120	**203**	80 to 93	11.5	[47]
GE 1.7-103	1.7	103	**204**	80		[47]
Vestas V110	2	110	**211**	80 to 125*	11.5	[47]
Gw121*	2.5	121	**216**		9.3	[49]
GE 2.5-120	2.5	120	**220**	110/139	12	[47]
NORDEX N117	2.4	117	**224**	91/120/141	11	[48]
Above 2.5 MW						
Acciona AW 132 *	3	132	**219**	84 to 120		[47]
Senvion 3.4M140	3.4	140	**221**	107 to 130	11	[47]
NORDEX N131	3	131	**223**	99/114/134	11.5	[47] [48]
Alstom 122	2.7	122	**231**	89 to 139	10	[47]
Vestas V136-3.45	3.45	136	**238**	149 to 160	11	[47]
GE 3.2-130	3.2	130	**241**	85 to 155	12.5	[47]
Siemens 3.3-130	3.3	130	**248**	85 to 135	13	[47]
Enercon E-141 EP4	4	141	**268**	129/159	14	[45] [47]

* IEC class IIIB

Table 4.2: LWST models available in the market. Data updated to July 2016.

5

Why is low specific power better for the system?

5.1 Effects of low specific rating

A lower specific rating in a turbine implies larger rotor at the same rated power, lower rated power at the same rotor size or a combination of the two.

As a comparison, three different turbine models are considered:

- Gamesa G114 - 2 MW ($SP = 196\ W/m^2$)
- Nordex N100 - 2.5 MW ($SP = 318\ W/m^2$)
- Vestas V90 - 3 MW ($SP = 472\ W/m^2$)

Figure 5.1 shows their respective power curves plotted against a Weibull wind distribution at 100m for an average site in North Germany (Schleswig-Holstein), taken from the Global Wind Atlas [54]. The average wind speed is 7.4 m/s and the Weibull parameters: $k = 2.46$, $A = 8.38$. The site is not very windy and, as far as average wind speeds are concerned, would be classified adequate for IEC Class III turbines. As it is possible to note, due to the larger area, the lower the specific power, the more the production is at low and intermediate speeds. For example, at 8 m/s, Gamesa G114 has a power output which is 70% higher than the Vestas V90.
On the other hand, due to the lower absolute power rating, the turbines with a lower specific power reached already their nominal power and therefore have a reduced power output at higher wind speeds.

As can be seen in the figure, for a site as the one represented, the benefit of a lower specific rating is relevant since the probability of having a wind speed equal or below 11 m/s is 89%.
With the increase of the quality of the site in terms of average wind speeds, the advantage of the turbine with lower specific power is reduced, since the wind speed exceeding rated power is increased. In general terms, for each wind conditions, a certain specific power configuration is giving the largest annual energy production (AEP), and the more windy the site is, the more convenient is a higher SP rating.

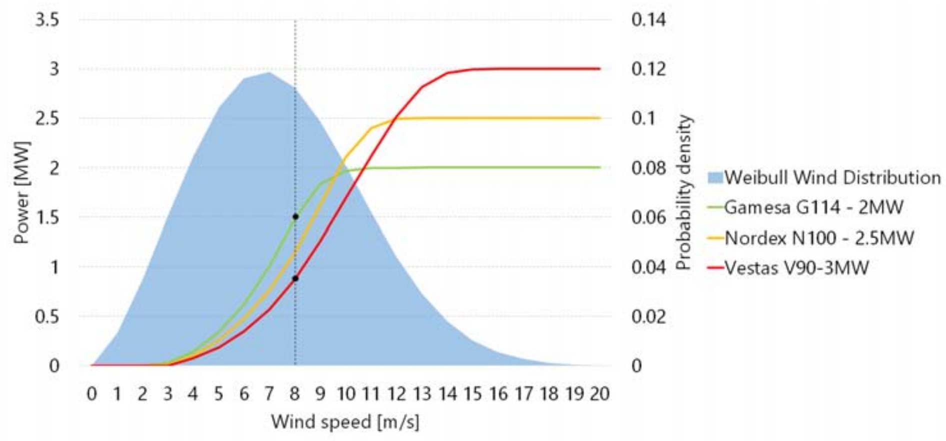


Figure 5.1: Weibull wind distribution for a German site and three power curves with different SP.

There is one thing that is constant regardless of the AEP: wind turbines with lower specific power produces more at lower wind speeds and less at higher wind speeds. These feature, as will be shown in the analysis, is the main advantage of such an advanced technology.

Fluctuations and capacity factors As a result of what seen before, the use of lower SP turbines change the pattern of wind production. At the same total production level, the generation at lower wind speeds increase, while the one at higher wind speeds is reduced.

Results from a simple simulation of two specific power levels (400 and 200 W/m^2) in Germany follows, assuming the same specific power technology was deployed across all country. The same total wind production is imposed to the two turbine simulations, equal to roughly 40 TWh.

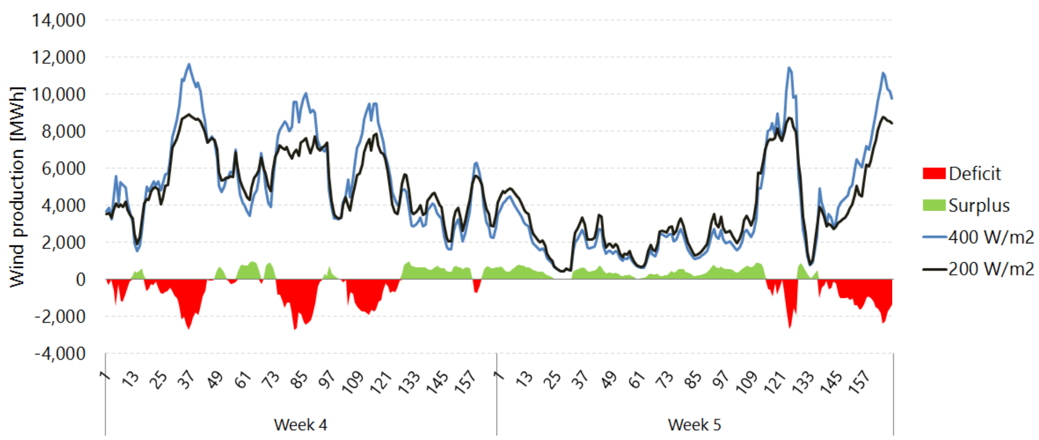


Figure 5.2: Comparison of time series of production for two different SP technology.

Figure 5.2 shows the different behavior in terms of generation fluctuations for a period of 2 weeks and the hourly difference in production. The *deficit* of production for the lower SP compared to the higher is located in hours of larger production, i.e. higher wind speed. On the other hand, the 200 W/m^2 technology produces more at lower production levels.

Figure 5.3 compares the wind generation duration curves for the two cases.

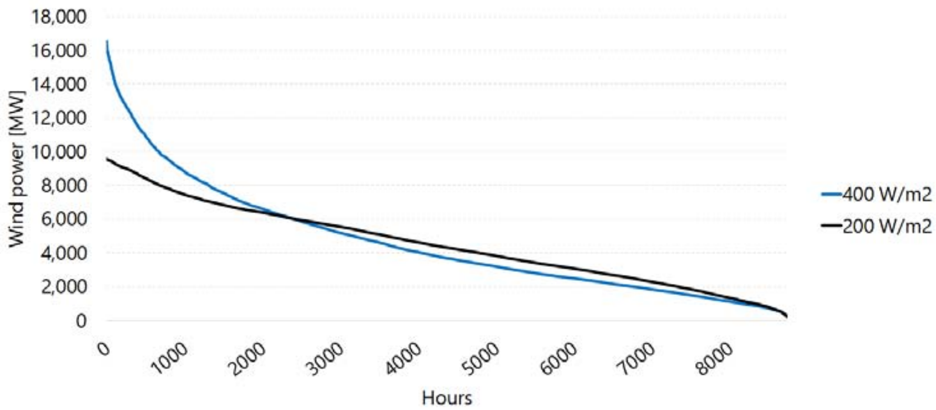


Figure 5.3: Comparison of wind generation duration curve for two different SP technology

As can be seen, there is a large gap between the duration curves of the two technologies, with the lower SP having much less spikes of production and a more flat wind duration curve.
Since the total wind production is the same in the two cases and the capacity installed is much less, the capacity factors for the technology with 200 W/m^2 are much higher than for the one with 400 W/m^2.

Residual load duration curve and system costs The reduced steepness of wind duration curve has a large effect on the residual load to serve, making the residual duration curve less steep as well. This results in potentially lower system costs to serve the load.

Effects on the market value As shown in Figure 5.3 the production from turbines with lower SP is more smoothened than for higher SP. The reduced capacity installed and lower peak would likely reduce the price-depressing effect in the hour with very high wind, diminishing the merit-order effect and ultimately the price drop.

Understanding the magnitude of these effects, in combination with other integration measures and in a realistic European setup is the main focus of this work and will be presented in the *Results & Sensibility* Part.

5.2 Other benefits for the system

There are a number of other system benefits from the use of low specific power turbines, well summarized in [9]. Among those, it is worth mentioning:

- Larger areas to develop wind farms, due to the opportunity of using lower wind speed sites, with the potential effect of reducing opposition and conflicts
- More production per installed capacity, due to the higher capacity factors
- Reduced need for transmission of large amount of energy in hour of high wind, with a general alleviation of congestions and a potential reduction in the peak transmission capacity

Some argue [8] [9] that the use of turbines with lower specific power, would reduce the forecast error and ultimately the balancing service cost.
Two effects are taking place following the reduction of specific power. Firstly, the turbine is producing more hours at rated power, where forecast is easier. On the other hand, since the power curve is steeper before reaching rated power, the error on the power output is higher for intermediate wind speeds. The first effect, together with the fact that the total capacity in the system is lower, seems to counteract the increased steepness of the power curve.
More research in the topic of forecast error and balancing service requirement is needed to give a more definitive answer to the topic [8].

5.3 The drawback of lower specific power

The main drawback of using turbines with an advanced design is that reducing specific power could result in a sub-optimal cost minimization, meaning that the solution does not feature the minimum LCoE.

This applies in particular to site with a higher average wind speed, for which turbines of IEC class I or II would be normally used. In order to reach this lower level of specific power, the potential resource available at high wind situations is not completely harvested due to the lower rated capacity, potentially reducing the annual productivity and thus increasing the LCoE.

The increase in the LCoE is in this context justified by the increased value of electricity generated and has to be seen in the general picture of switching from considering the mere cost to jointly assess cost and value.
The optimal design lays somewhere between a *low cost/low value* turbine and a *high cost/high value* one.

Part II

Modelling

6

Energy System Modelling

6.1 Energy system models as tools for decision making

Energy models are being increasingly used around the world to provide insight into the potential evolution of energy systems in the years to come. The long time horizon of energy investments, both in generation and transmission, as well as the increasing need of information for policy design, makes it necessary to understand the framework and characteristics of the future energy systems. Moreover, the vision of a low carbon energy system and the progressive switch to RES that has emerged in the last few years, need to be studied in depth.
The integration of such new technologies with their technical constraints, uncertain cost evolution and efficiency, needs to be analysed under different scenarios in order to provide insights for policy design and decision making [55].

More and more, informed decision making in the energy sector is based on quantitative models which are able to represent and reproduce the main dynamics of the system and its various sub-systems [55]. As a consequence, many energy modelling tools exist and they differ a lot depending on the scope of the analysis, the system considered and the characteristics of the model.

A detailed categorization and comparison of different energy system tools used for renewable integration studies, is presented in [56]. The categorization of the tools is based on the following definitions:

- **Simulation tool**: simulates operation of a system to supply a certain demand.
- **Scenario tool**: combines a series of years into a long term scenario. Typical time horizons are 20-50 years.
- **Equilibrium tool**: explains the behavior of supply, demand and prices in a whole economy or part of it.
- **Top-down tool**: macroeconomic tool using data to determine growth in energy prices and demands.

- **Bottom-up tool**: identifies, defines and analyses the specific technologies involved in the system and identifies investment alternatives

- **Operation optimization tool**: optimizes the operation of a specific system (typically Simulation tools)

- **Investment optimization tool**: optimizes the investments in a specific system (typically scenario tool)

For this master thesis study, which focus is on the system effects of deploying different wind turbine technologies in the future, there is a need for a tool characterized by the opportunity to perform scenario analysis in the long term.
Secondly, in order to simulate the effect of wind in the day-ahead market, an optimization of operations and market equilibrium based on economic dispatch is needed. Moreover, to capture the evolution of the system in the long time horizon, the option to optimize the investments in new capacity is a prerequisite as well.
Finally, given the international geographic scope of the study, the tool has to be able to handle multiple countries.

Given the requirements just expressed, Balmorel model [57] is a suitable tool for this Master Thesis project.

6.2 Balmorel model in brief

Balmorel, the "BALtic MOdel of Regional Electricity Liberalized", is an open-source model for analysing the combined power and heat sector, available at [57]. It was originally developed by ELkraft (now Energinet.dk) and the Technical University of Denmark (DTU). The model is coded in GAMS, the General Algebraic Modeling System, which is a high-level modelling system for mathematical programming and optimization [58].

The model has been used both by the Systems Analysis Division at DTU Management Engineering and EA Energy Analyses for a large number of projects, most of which related to Denmark and the Nordic Countries. In addition, Balmorel projects have been carried in Germany, Mexico, Vietnam, China, Western africa, South Africa and Eastern Africa [59].

Its main characteristics well fit with the analysis requirements, being it a bottom-up, linear and deterministic model, with the possibility for both investment and dispatch optimization. Additionally, the model is a partial-equilibrium tool, since it represent with a good detail only heat and power sector, as opposed to general equilibrium models which include all sectors and have a macro-economic perspective.

A more detailed description of the model, in terms of geography, technologies and dynamics, is available in Appendix A, while a presentation of the model setup is shown in Figure 6.1.

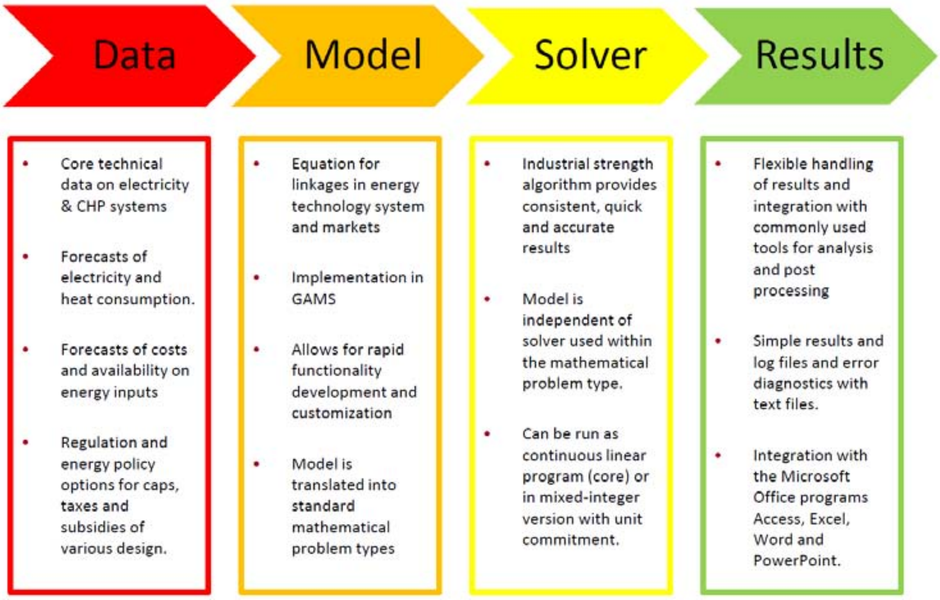


Figure 6.1: Balmorel model setup. Source: [59]

Assumptions and limitations of the model

There are a number of general assumptions which the model is based on, which will be presented below.

First of all, the model assumes that all the power is traded in the day ahead market. Secondly, perfect competition in the market is assumed, meaning among other things no exercise of market power is possible. In reality, power and heat sector are still subject to market failures. Moreover, the model has perfect foresight of the future and optimizes based on the total amount of information available. This can lead to optimal solution which in reality would not practically hold, due to the uncertainty in key parameters such as hydro inflows, wind speeds, irradiation and demand level. On the other hand it gives the advantage that all scenarios are optimal, making them easier to compare.

Beside the assumptions just presented, the model has some further limitations:

- Uncertainty of the inputs: due to the very large amount of data in input, many of which representing projections of costs and performance in the future, the results from the model are largely dependent on the data in input. This limit is not specific to Balmorel, but in general related to modelling simulations.
- Short sight in investment optimization: when optimizing investments, the model takes into account only one year. If the plant pays back the annuity of the total investment, the plant is invested in. As a consequence, the condition of the future system are not taken into account.
- No representation of internal grid: each region in the model is considered a copper plate and no detailed representation of the internal grid is present in the model. However, transmission capacities between regions are represented.

- No consideration of power flows: 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.

Status of Balmorel model and improvements performed

Thanks to the large amount of projects carried on so far with Balmorel, the setup of the model is quite well defined. A detailed description of Denmark, Germany and the Nordic countries is already present, together with an overall representation of all the other European countries. Data on plants, demands, as well as exogenous parameter for future renewable plans and goals are available and implemented.

Beside the implementation of specific data related to the goal of the study and the inclusion in the model of different technologies of wind based on the SP, the effort in the project has been placed in reviewing and improving the methods used to model wind power production.
Specifically, calibration and update of existing parameter has been carried on together with the development of a new way to describe the smoothening of the aggregated power curve for the future technologies, which is presented in detail in Chapter 8.

7

Modelling the value of wind in the power system

7.1 Analysis focus and framework

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

The technology scenarios chosen are related to two parameters already introduced: specific power and hub height. Dedicated scenarios are developed for each of the two parameters to assess their contribution separately.

The idea of the study is to have a "policy-maker" approach by simulating the system development in the next 15 years, considering existing policies and targets, as well as plans for RES roll out and transmission expansion. This approach complement what in literature has been defined as *medium-term perspective* [4], with projections on the expected development based on national and European plans. The distinction between short, medium and long term perspective has been categorized in [4] based on the way the capital stock is treated. In the short term existing capacity is given and only dispatch is simulated. In the long term, a green-field approach is used where no capacity is given and the system is optimized via investment model. With a medium-term approach, existing capacity is included but the system can adapt to evolving conditions and parameters through endogenous investments and disinvestments. The result of using a medium-term perspective and exogenous inputs is a more realistic representation of the system and its future evolution, based on the information available and country commitments today.

Another thing that is worth mentioning is that existing fleet is modelled and included as part of the capacity generation stock, together with assumptions of the progressive future decommissioning. On the other hand, all the scenarios related to the technological design of turbines applies to future installations only, which adds on top of the existing fleet. By doing so, the value of wind is affected especially in the short time, since the historical fleet and installations of future technology will have a different production based on their diverse technological characteristics. With respect to this, not taking into account historical capacity and modelling wind as "all advanced" or all "all conventional" could result in overestimating the benefit for onshore wind of switching to advanced design in the coming 15 years.

Timeframe

The timeframe selected for the study is up to 2030. Model simulations are performed for 2015 as a historical base year and consequently for 2020, 2025 and 2030.

Geographical scope

Almost the entire Europe is modelled in Balmorel, with the exclusion of Iberian peninsula and Balkan countries. The model includes a detailed representation of the Nordic countries and Germany, together with an overall representation of the rest of Europe. The list of countries included in the simulations is the following: Norway, Finland, Sweden, Denmark, Estonia, Latvia, Lithuania, Germany, UK, France, Belgium, Netherlands, Switzerland, Italy, Austria, Poland, Czech Republic.

While all these countries are modelled, the focus of the study is be placed upon Germany, used as a test case. The rationales behind the choice relates to the level of detail in the modelling, the importance of Germany in the European energy context, but in particular to the ambitious goals for onshore wind development.

7.2 Assumptions and modelling choices

General assumptions

Some general assumptions, which relate both to the model itself and to specific choices of the analysis, follow:

- All energy produced is assumed to be traded in the day-ahead market. As it was underlined in Chapter 4, even though the trend is toward increasing volumes traded in EPEX, this is not the case today.

- In each scenario, the technology chosen is implemented not only in Germany, but in all the countries modelled.

- Advanced turbines in terms of both lower specific power or higher hub heights are assumed to be installed in each wind area regardless of wind conditions or the IEC class of the turbine model. This reflects the considerations expressed in Section 4.6.

Finally, it has to be underlined that the analysis is limited to the day-ahead market and neglect intra-day market, balancing market, possible bilateral contracts, as well as effects such as forecast errors and grid-related costs.

Time resolution

With a medium-term perspective, having a model which can perform investment optimization is fundamental, both to ensure decommissioning of capacity which is not competitive and to optimize the system with additional investments. Moreover, since a certain wind penetration in terms of annual onshore generation is fixed exogenously, investment run ensure that the capacity needed to fulfill this requirement is installed in each scenario, depending on the characteristics of the technology.

Investment optimization simulations are characterized by high computational demand and a reduction of temporal resolution is usually required [60]. In Balmorel, the simulation features both a selected number of weeks a year and a reduced amount of hours per week, chosen as representative for investment decisions.

On the other hand, as underlined by [61] and [62], the temporal resolution has a great importance when modelling VRES systems and in particular 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 since more extreme events, which are only present in the high resolution cases, have particularly strong price effects [62].

Given the two requirement for investment and dispatch in terms of temporal resolution, the setup of the study is the following:

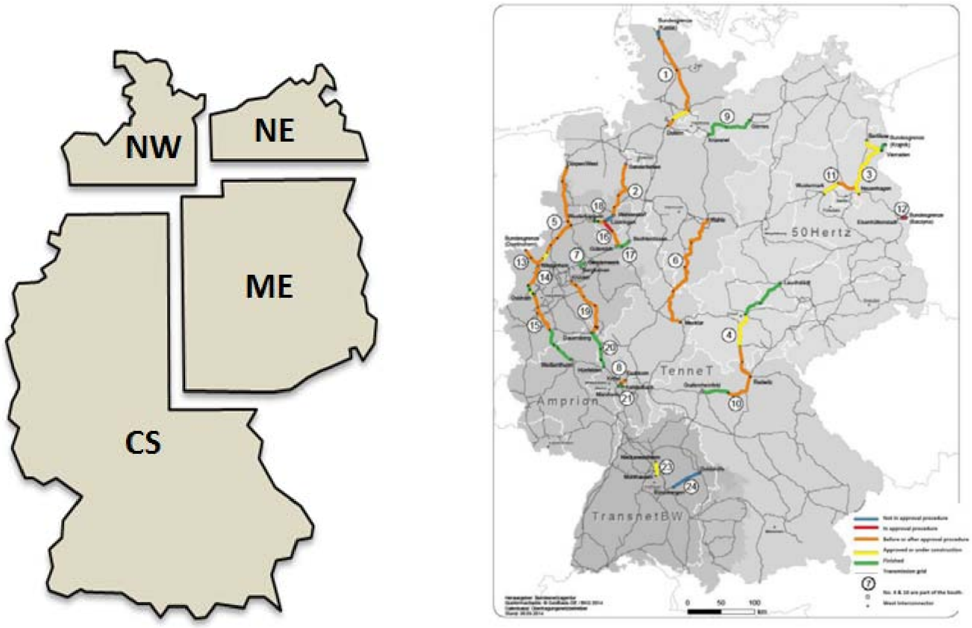
- Investment optimization with a lower time resolution, to have acceptable running time
- Dispatch optimization performed using the results of the investment simulation, with hourly resolution, in order to better capture wind interaction with the market and to correctly assess the MV of wind

Internal grid and congestions in Germany

In Germany, the current EPEX day-ahead market setup consists in one single price zone (together with Austria) [30]. In reality, internal congestion in the German grid sets limitations on the possible flows across the country and in particular in the corridor North-South. This is managed by counter-trading, which is performed by the TSOs after market clearing to make sure the system operates within its limits in terms of NTC [63].

The standard approach for modelling Germany in most of the analysis in Ea Energy Analyses is splitting the country into different market zones and consider the bottlenecks in the system. On the other hand, in few previous analysis in Balmorel, among which [63], Germany has been treated as a single price zone. This corresponds to assume solved all the internal grid congestion and treat Germany as a copper plate. For the sake of this study, which analyses wind generation patterns and the system value of wind, this assumption would be too strong. As a consequence, Germany is modelled with 4 price zones, which are highlighted in Figure 7.1(a). With this setup, internal grid constraints can cause the four zones to have different prices, especially in hours with high wind generation in the North. This modified dispatch in the four regions is supposed to take into account the TSO congestion management and re-dispatch, as well as the limits imposed in the NTC to other countries. The limitations of NTC to the Nordic countries due to internal congestion is evident in data from [1], while its correlation with RES production in Northern Germany is documented in [64].

The choice of the four zones is a result of an analysis of re-dispatched power plants and congestion management for historical years (already done internally at EA Energy Analyses) and is meant to reflect the main grid bottlenecks which are located mainly between DE-NW and DE-CS, as well as between DE-ME and DE-CS. Figure 7.1(b) shows the main expansion projects along these directions.



(a) Modelled regions

(b) Planned grid expansions

Figure 7.1: (a): Subdivision of Germany into four regions in the model.
(b): Expansion plan for the internal grid in Germany. Source: [65]

Since this is a different setup compared to the actual market in Germany, the resultant value of wind has to be understood more in a system and socio-economical sense, rather than a projection of what wind investors will gain in the market.

Hydropower dispatch

It is important to briefly specify how the model performs dispatch of hydropower due to its influence on the results. In the investment runs, a value of hydropower production is fixed for each week. The value is then used in the hourly runs to set the production for the correspondent week. Since the dispatch is different in each scenario, some variations in the annual hydropower production can result from the simulations. These differences in the total level of annual hydropower are taken into account in the total system costs.

7.3 Definition of scenarios

Taking into account both the focus and framework of the analysis and the modelling choices, especially in terms of temporal resolution, the different scenarios analysed are presented.

The main idea is simulating the effects of the turbine design separating contributions from hub heights and specific power. After a base historical run of the year 2015, which provides the basis for the projections, 6 technology scenarios are simulated up to 2030 with 5 years steps.
In the first set of scenarios, three turbine technologies with different specific powers are varied while hub height is kept constant. This set is called SP scenarios.
The second set is named HH scenarios and three technologies with the same specific power and three different hub heights are assessed. The central scenario, which will also serve as a reference, is shared by the two sets.

In order to decide the levels of the SP and HH to be simulated, the market summary and the technology trends presented in Section 4.4 are used as a basis.

Regarding specific power, the three level chosen are **400 $\mathbf{W/m^2}$**, **300 $\mathbf{W/m^2}$** and **200 $\mathbf{W/m^2}$**. The average SP of turbines approved and commissioned in Germany the last 2 years was found equal to 360 W/m^2. A large part of these installations are in the 300 W/m^2 range, while the rest of turbines are 400 W/m^2 or above. Therefore, the current level of specific power have to be considered laying between the 300 and 400 W/m^2 scenarios. The last and lowest level is representative of advanced design and of the so-called *low wind speed turbines*, presented in Section 4.5.

As for the hub heights, the three scenarios feature **90m**, **120m** and **150m** respectively. The central scenario represents the current average value of new installations in Germany. While the advanced hub height scenario represents values reached by the latest models in the market, the lower scenario is representative for older models in the German industry.
Figure 7.2 graphically displays the scenarios simulated.

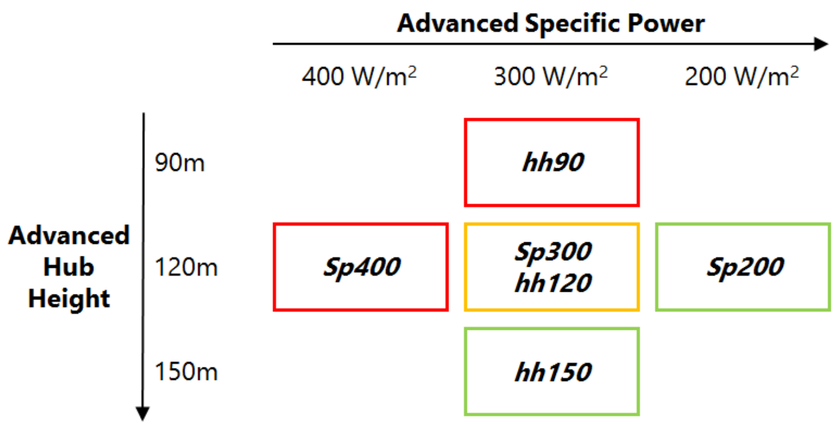


Figure 7.2: Technology scenarios simulated in the study.

Regarding the simulations setup, a common framework is established with general assumptions regarding fuel and CO_2 price projections, transmission expansion and exogenous development of RES-E and all the other model assumptions. Consequently, the following steps are:

- **Investment run** for each technology scenario and year: set the capacity of the specific technology to fulfill the annual target and enables the system to adapt and optimize by means of investments and disinvestments.
  Resolution is reduced by means of *time-aggregation*, with a total of 12 weeks simulated in the model, each composed by 6 representative hours.

- **Dispatch run** for each technology scenario and year: import the result from the respective Investment run (system configuration) and optimize the dispatch over a year.
  Resolution is 8736 hours, corresponding to 52 weeks (hourly temporal resolution).

In Part III, results of capacity installed and general system configuration are given by the investment run, while all the rest of the results, including wind generation pattern, load duration curves, curtailment, total system costs and value of wind are based on the output of the dispatch run.

Figure 7.3 summarizes the simulations and scenarios setup.

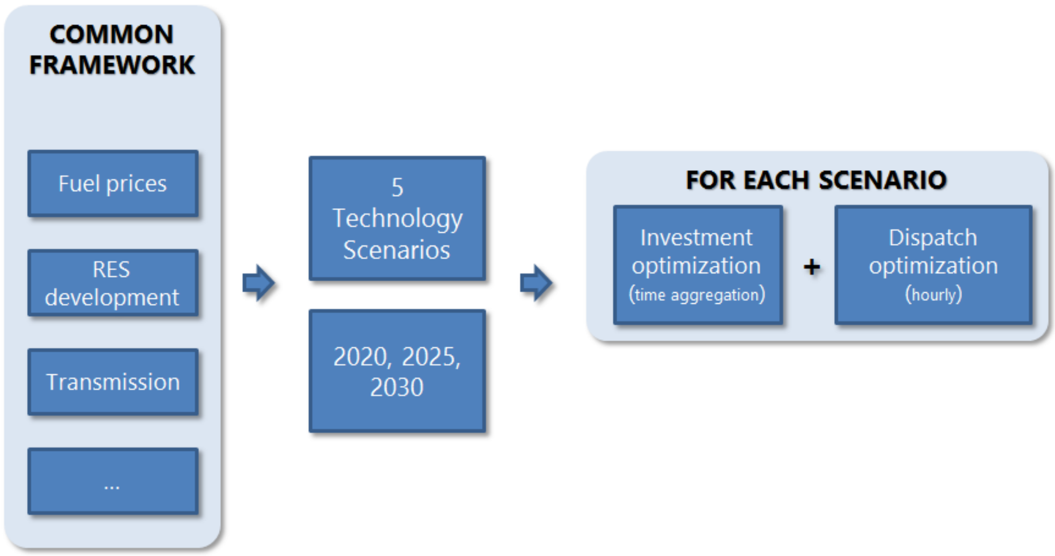


Figure 7.3: Setup for the simulation of the different scenarios in Balmorel.

7.4 Main data assumptions and inputs

In this section the main data assumptions for the analysis are presented. As mentioned, Balmorel is a model with a broad scope both in terms of technologies represented and geography. Since the amount of input data is very large, the focus will be on the data that mostly affect the current analysis.
Specifically, the following sections deals with data which has been changed or updated. Sources for other inputs which are relevant for the study are mentioned here and visualization of data assumption is shown in Appendix B.

Policies and available technologies

Assumptions for 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 [63].

Without going in too much detail of the many assumption underlying the model, some of the main ones are the following:

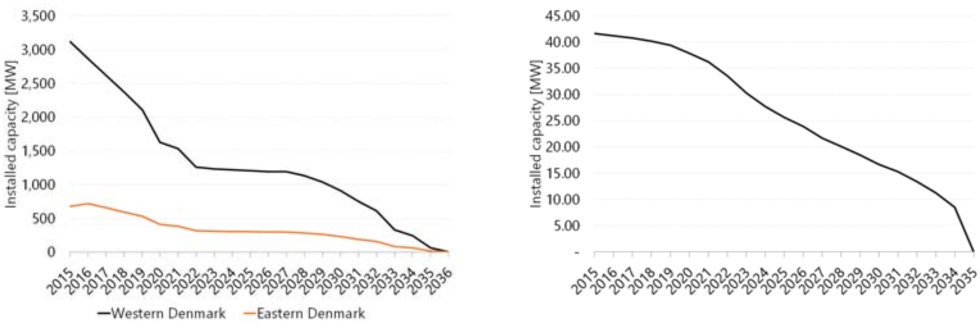
- No endogenous investments in Germany for nuclear allowed and decommission of the current plants, following the phase-out plan of the country [28]
- Exogenous development of Nuclear for other countries such as Finland, Sweden and France, based on the announced government plans
- No Carbon Capture ans Storage (CCS) technologies available, due to the fact that the technology is not projected to be cost-effective and widely deployed by 2030 [66]
- No new investments in oil and coal in Denmark, reflecting the current plans for conversion to biomass of the major plants [67]

Wind power

Historical wind capacity and decommissioning The historical wind power capacity in input to the model has been updated to represent the situation at the end of 2015 for Denmark and Germany.
The sources for the figures are [67] and [68] for Denmark and [69] for Germany, which contains a distribution of installed capacity divided per Bundesland (federal state).
The capacities for the rest of Balmorel regions and countries are updated to the end of 2013.

Another important aspect related to the historical fleet is the rate of decommissioning, since it affects the repowering and the room for new capacity in the system.
The decommissioning has been modelled assuming a lifetime of 20 years from the installation year. For Germany, the data about installation years are taken from [28], while for Denmark they are based on [68]. Due to availability of disaggregated data, decommissioning in Denmark is divided by region, while for Germany it is considered equal in all four regions.

Figure 7.4 shows the decline in available historical capacity per year for the two countries.



(a) Denmark (b) Germany

Figure 7.4: Modelled decline in the historical installed capacity for Denmark and Germany.

Onshore Wind penetration levels The different wind technologies in terms of hub height and specific power are simulated with the same wind penetration level across scenarios.
As a consequence, there is a need to specify the level of wind production in terms of TWh produced in each of the county modelled for the years 2020, 2025 and 2030.

The data on RES in the model is a result of an extensive analysis previously carried out by Ea Energy Analyses of assumptions from Vision 3 and Vision 4 of the ENTSO-E 10-year Network Development [70] and National Reneweable Action Plans (NREAP) [71], as well as country targets specified by TSO and national authorities. For Germany, the data was complemented by Renewable Energy Act (EEG) and Netzentwicklungsplan (NEP), while for Denmark Energinet.dk assumptions [67] and the Danish Energy Agency were used.

In the Balmorel setup previously available at Ea Energy Analyses, target for wind development were specified in terms of capacity for Germany and the Nordic Countries until 2030 and for the rest of the European countries only until 2025.
As a consequence, two main issues had to be solved: transforming capacity targets to production values and setting wind generation levels for other EU countries in 2030. In order to do so, an investment run with the base model setup is performed for the years 2020, 2025 and 2030 and consequently the resultant values in terms of wind generation (TWh) are imposed exogenously in the various technological scenarios.

The resultant penetration levels for each countries, which will be exogenously imposed in all technological scenarios, are summarized in Figure 7.5.

Regional distribution in Germany In order to correctly model the development of wind installations in Germany, in particular with respect to geographical distribution, the penetration targets for the country has been split into the four

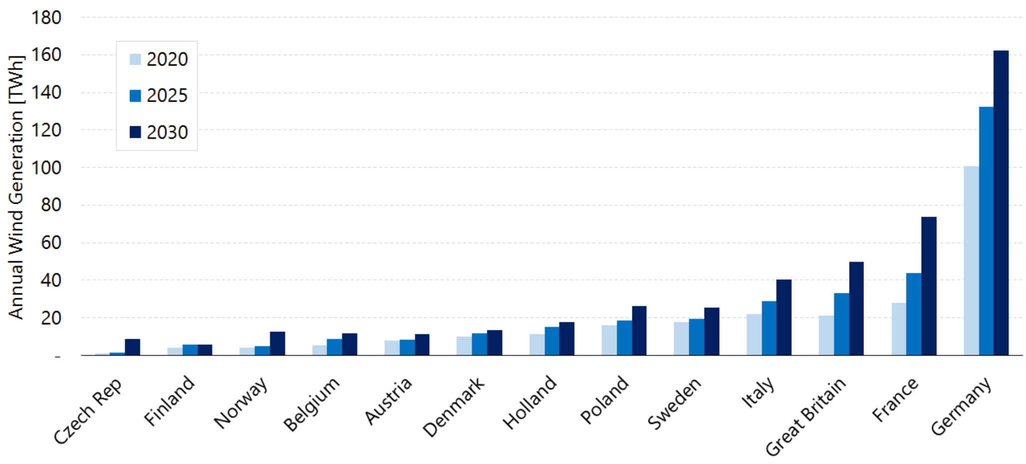


Figure 7.5: Exogenous onshore wind penetration level for each country. (Countries with less than 1 TWh of production are not included in the graph).

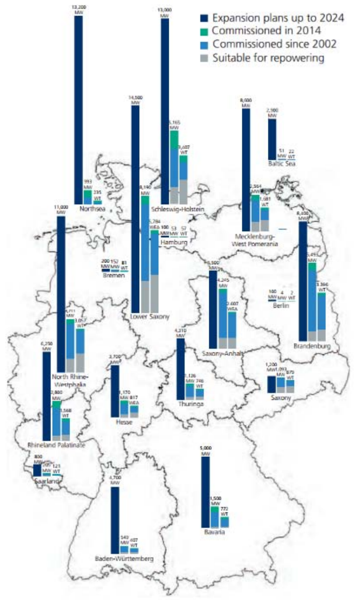
different Balmorel regions.

In the previous model setup, in which only a total regional potential was specified but regional allocation was missing, the model tent to install all the wind capacity available in the region with highest wind resource, i.e. DE-NW, resulting in unrealistic wind capacity roll-out which affected the resultant value of wind as well.

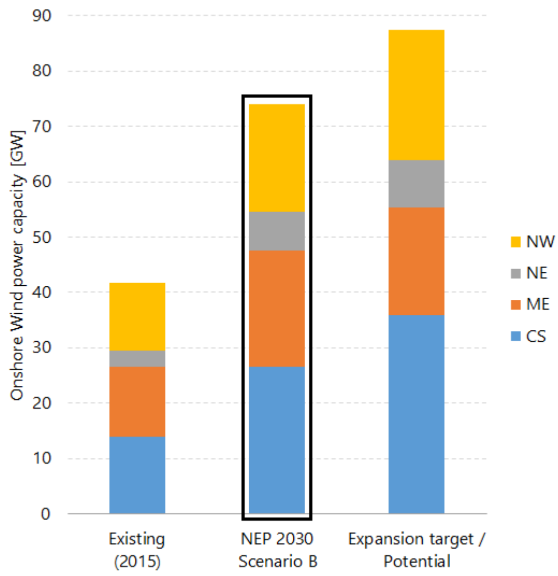
Firstly, the distribution of future wind power installation from Scenario B of NEP Szenariorahmen 2030 [72](expressed in capacity terms) is allocated to each of the four Balmorel region. Secondly, assuming a reference number of FLH per region, the distribution is transformed from capacity to production. Finally, the numbers are expressed in percentage terms, with respect to the total wind production.
In all future years, these percentages represent the regional distribution of the total wind penetration level defined above.
Figure 7.6(a) shows the capacity distribution for each Bundesland and the expansion targets based on consultations for NEP Szenariorahmen 2024 [73]. Figure 7.6(b) compares current onshore wind capacity distribution [69] with Scenario B of NEP Szenariorahmen 2030 and the aforementioned expansion targets.
Figure 7.7 summarizes the final distribution in terms of production applied in the model: 29 % in North West Germany, 9 % in North East, 28 % in Middle East and 33 % in Center-South.

Other RES-E Development

Similarly to onshore wind, the development of the other RES-E is fixed exogenously in order for the scenarios to be comparable.
The motivation for this approach is that the levels of RES-E deployment in the electricity sector may to a great extent be driven by national policies, RES targets and support schemes [63]. In particular, solar and offshore wind development in terms of capacity installed are fixed based on the same references as onshore wind, expressed in the previous section, namely ENTSO-E, NREAP and other national sources.



(a) Expansion targets



(b) Capacity distribution

Figure 7.6: (a) Expansion target/wind potential by federal state, corresponding to Scenario C of NEP Szenariorahmen 2024. Source: [74].
(b) Distribution of capacity today, in NEP Szenariorahmen 2030 and Expansion targets.

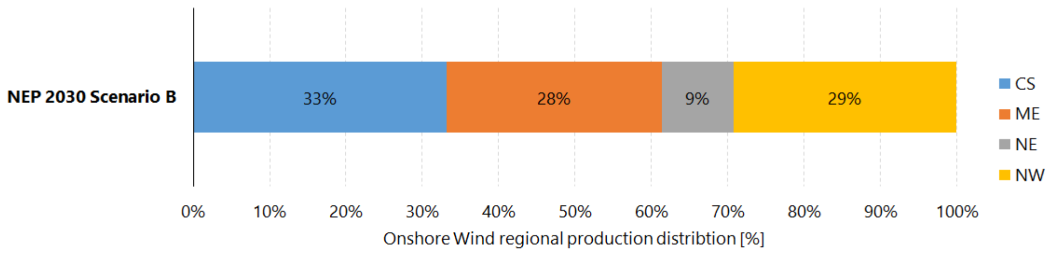
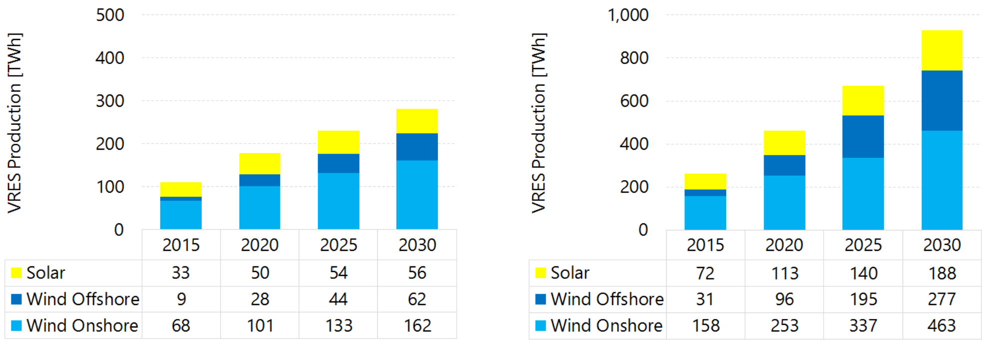


Figure 7.7: Resultant rgional distribution of production for each future year (2020, 2025, 2030).

Figure 7.8 summarizes the VRES roll-out in Germany and the entire system, which is exogenously fixed in the model.

Electricity Demand

Projections of gross electricity demand from 2020 to 2030 for all EU countries are based on the scenarios assumptions for ENTSO-E's 2016 ten-years network development plan [75].
For the year 2030, an average of the values for Vision 2 and 3 has been considered. All the assumed projections are net demands, including both effects of energy savings, as well as contributions from electrifications of sectors such as individual heating and transport. Regarding values for historical years and up to 2020, including



(a) Germany (b) Entire System

Figure 7.8: Exogenously imposed VRES penetration levels for Germany **(a)** and the entire system **(b)**.

regional distribution, national sources for the countries are used.
Electricity demand evolution for Germany and the entire system modelled are shown in Appendix B.

Fuel and carbon prices

Assumptions on fuel price development are based on a method developed by EA Energy Analyses [76] called *Convergence pathways*. Practically, the short-term focus is on forward and future financial contracts, while in the long term it is placed on the latest World Energy Outlook (WEO) by IEA [77], specifically on the scenario *450ppm*. As for the CO_2 price, the same approach is considered, but the level reached in 2030 is 15 €/ton. A visualization of the development of prices over time can be found in Appendix B. Both fuel and CO_2 prices are then varied in the sensitivity analysis to assess their effect on the main results of the study.

RE Subsidy levels

As mentioned in the previous section, in the reference scenario runs it is assumed that RES will still be subsidized in the future in order to comply with national targets. The level of subsidy assumed is in general much lower than historical values, due to decreased cost of the technologies and change in the subsidy mechanism, e.g. switch from feed-in tariffs to tenders. The values considered in the study are summarized in Table 7.1.

Technology		Onshore wind	Offshore wind	Solar	Biomass	Biogas
Estimated subsidy	[€/MWh]	15	25	30	15	25

Table 7.1: Subsidy levels for RES technologies expressed in real terms [2015-€/MWh].

In the sensitivity analysis (Chapter 10), the level of subsidy is subject to a deeper analysis, in particular with respect to its effect on power dispatch.

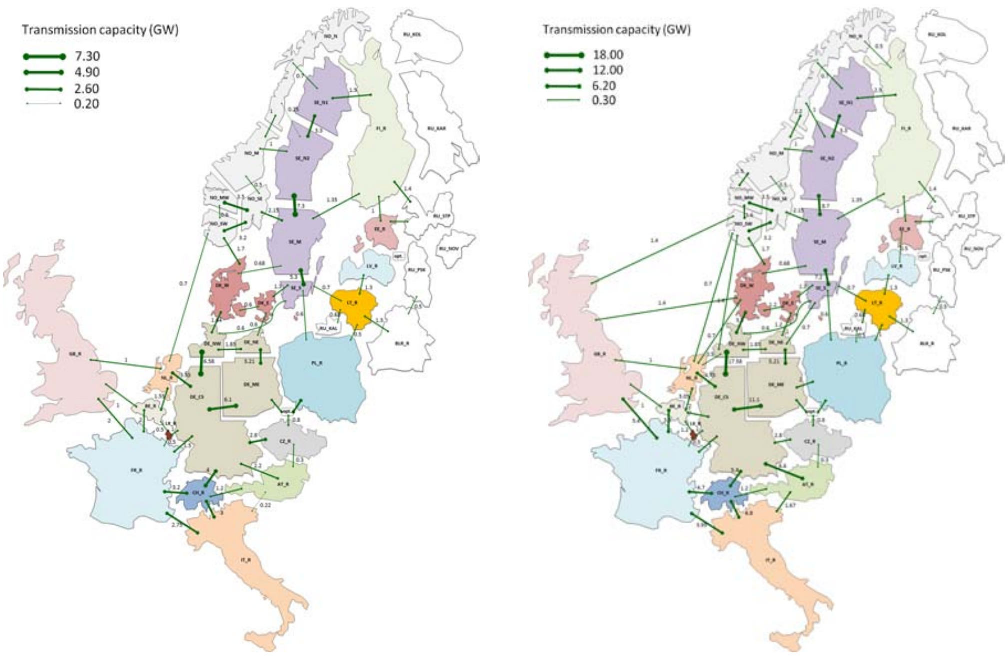
Net Transmission Capacity development

The assumed development of the net transmission capacities (NTC) is based on the ten-year network development plan (TYNDP) 2014 from ENTSO-E [70].
All projects planned for commissioning until 2030 are included in the analysis.
Regarding the development of internal grid in Germany, it is assumed that major projects aimed at relieving the internal North-South congestion are realized in the period 2015-2030.
Due to the controversial ongoing discussion in Germany, the most debated expansion corridors are assumed to be delayed from 2020-2022 to 2025. Recent announcements (June 2016) about official delays in the grid development moved the commissioning date of SuedLink and SüdOstLink to 2025 [65], confirming the assumption made in the model. Nevertheless, some of the new line which in the analysis were assumed between 2020 and 2025, in practice have been further delayed.
The specific assumptions are summarized in Table 7.2. The largest increase in the transmission to 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.

From region	To region	2015	2020	2025	2030
DE-ME	DE-CS	6.1	6.1	9.1	11.1
DE-NW	DE-CS	6.6	7.6	13.6	17.6

Table 7.2: NTC in the German North-South corridor, expressed in GW.

A comparison between NTC in 2015 and 2030 is shown in Figure 7.9.



(a) **2015** (b) **2030**

Figure 7.9: Net Transmission Capacities across Balmorel regions in Europe in 2015 and 2030. Visual elaboration of inputs to the model.

8

Modelling wind power production in Energy System Models

8.1 Requirements for the analysis

There are a number of technical and qualitative requirements for the analysis carried on in this thesis with respect to the modelling of wind power, most of which are shared with any numerical energy system optimization. They can be summarized below:

1. Representative wind generation profiles for each market area modelled in Europe
2. Correlation of wind generation profiles across space and time for different countries
3. Reduced complexity and computational time
4. Possibility to assess different technologies of wind turbines (i.e. different power curves)

Keeping this in mind, alternative modelling solutions are assessed.

8.2 Alternative modelling approaches

When simulating power systems with large penetration of wind, the representation of the fluctuating output from wind farms is needed.

There are very few published studies that are focused on the power output of nation-sized wind fleets [78]. Moreover, a general lack of consistency has been found in the characteristics of modelled time series in a number of energy system studies. As a result, in particular with increased wind penetration, the system could look very different depending on how wind time series are modelled [79].

There are substantially three methods of modelling power production time series in large scale energy dispatch models:

- Wind generation profiles
- Wind speed profiles and regionally-aggregated power curve
- Wind speed profiles and power curve at farm level

The first method is the one used for most of the analysis done with Balmorel model in the past and has been the modelling practice for long.
While it is more direct and keeps the characteristics of the feed-in time series especially in terms of fluctuations, it has some downsides. First of all, when modelling a large scale system like Europe, detail data on generation time series could be unavailable for all the countries considered.
Secondly, adjusting generation profiles to take into account evolution of technology (increased FLH, changes in the power curves) is difficult and could introduce empirical processes of adjustment that do not match technological principles and result in much different feed-in profile characteristics, e.g. see a comparison between [80] [81] in Figure 8.1. It is clear from the graph that the two methods proposed to correct FLH in the generation profiles differs a lot from each other and none of them could be considered more correct than the other.

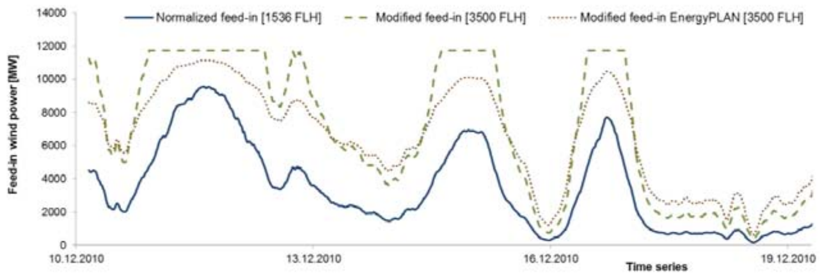


Figure 8.1: Results of FLH adjustment of generation profile due to increased SP. Comparison between [80] [81]. Source: [80].

Another alternative to produce wind feed-in profiles consists in using synthetic time series with statistical properties matched to historic data, like proposed in [78]. Beside being mathematically complex and therefore difficult to implement for a large scale model covering so many different countries, it also fails to consider the technology evolution already mentioned before. As a consequence, it is not relevant for this study and in general for the purposes of Balmorel model.

On the other hand, using wind speed data as an input enables to overcome these obstacles. It has to be noted that in the last few years, following the evolution of wind power installations and thanks to the interest all around the world, many satellite reanalysis databases and mesoscale meteorological models are starting to be available for every location in the world with a resolution down to 30-50 km.
Moreover, using climate data as input maintain consistent spatial and temporal correlations and offers other relevant parameters that could be useful in the modelling environment (such as temperatures, solar irradiation, etc.) [79].

The use of wind speed profiles with power curve at a farm level has been studied and used in [79] and [82]. Beside being computationally heavy and not suitable for Balmorel, in case of the need to model future wind generation ahead in time, the level of detail and the number of assumptions needed are very large (e.g. distribution of capacity build-out). For this reason, a more aggregated representation, with regional power curves was previously chosen for Balmorel and further developed in this study.

In order to translate wind speed time series into wind generation time series, there is a need of modelling the Wind-to-Power Converter, i.e. the wind turbine, for aggregated areas and for different wind technologies.
A precise and accurate model of the aggregated power curve is therefore needed in order to produce representative generation profiles. For this reason, effort has been spent in this study to understand dynamics of wind turbine aggregation at a regional or country level, both for historical and future technologies. The detailed modelling procedure followed is described in the following subsections.

8.3 Wind speed data

The current setup of the model at Ea relies on the use of Mesoscale wind data provided by *Vestas* for a previous project [*confidential data*]. One time series for each modelled region onshore and offshore in Germany and the Nordics is provided, while the time series for other EU countries in the model are derived from those with the attempt to keep the correlation and a reasonable number of FLH for the specific country. The limited access to Mescoscale data is justified by the proprietary and costly nature of the models and their outputs.
For this reason, an attempt to find a different data source has been performed, in particular due to the procedure developed for the smoothening of power curves, which needs a larger number of time series for different locations.

In the last few years, due to the interest for wind energy and the need for wind data, new sources of metereological information started to be available. Reanalysis data is a source of time series for different parameters such as irradiation, surface temperatures and wind speeds, produced by numerical weather prediction (NWP) models based on satellite observations and other weather observations.
In particular, the third generation reanalysis datasets have become available in the last several years and have started to be used in a number of studies and analaysis related to wind power. Among those, the leading ones are [83]:

- **CFSR - NCEP**: the Climate Forecast System Reanalysis. Horizontal resolution of 38 km. Spans from 1979 to 2010. Wind speed profiles available with hourly resolution at 10m [84].
- **MERRA**: the Modern Era Retrospective Analysis for Research and Applications. Based on NASA global data assimilation. Horizontal resolution of 38 km. Spans from 1979 to 2010. Wind speed profiles available with hourly resolution at 10m and 50m [85].
- **ERA**: the European Center for Medium-Range Weather Forecasts (ECMWF) reanalysis series (including ERA15, ERA40, and ERA Interim). ERA Interim

is the most recent. Horizontal resolution 80 km. Spans from 1979 to 2010. Wind speed profiles available with 3-hours resolution at 10m [86].

Due to the hourly characteristics, the relatively good resolution (38 km grid) and the ease of access, CFSR-NCEP has been selected among the options.

Internal analysis have been performed about the congruency with mesoscale data and the result confirmed previous analysis on the topic: some locations present a bias in the wind speed, showing lower wind speeds. Practically, the frequency distribution of wind speeds is shifted to the left towards lower values.

Beside downscaling models which are computationally heavy, easier and more direct processes of bias correction are described in some articles lately published or in review [87] [88]. Moreover, they have been used in other publications [82] [89], even though not clearly formalized.
A possible correction of biases using Weibull parameters from the Global Wind Atlas has been discussed but, due to the amount of work needed, will be subject of a future study.

In this analysis, it has been decided to stick to Mesoscale wind data as input for the different regions in the model.
On the other hand, due to the need of various wind speed time series in orfer to represent a large number of locations, reanalysis data from CFSR-NCEP will be used as input for the power curve smoothening of future capacity, which will be described in Section 8.6. By doing so, an imprecision in the process is introduced, while it is arguable that correlation and diversification of speeds is still represented in the data, even if biased.

8.4 Wind-to-power Module

In this section, the principles used to convert wind speed data to power generation profiles is described in detail. A general schematic of how the model works is shown in Figure 8.2.

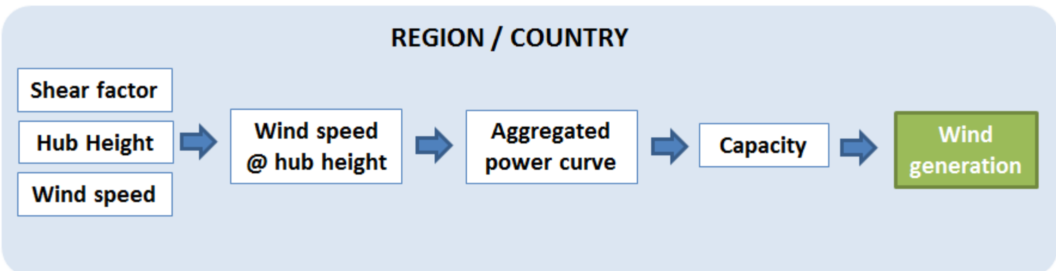


Figure 8.2: Schematic representation of the wind modelling in Balmorel.

Wind areas

First of all, it has to be noted that in order to maintain the correlation with other time series in input to the model, such as solar generation, power demand, hydro inflows, etc., the year used for the wind time series is 2001.

In the model, a certain number of wind areas are defined. Each wind area corresponds to a Balmorel region, e.g. DK-East, France or DE-NW. As a consequence, each region or country is represented by a certain wind speed time series, given at a specific hub height. The time series describes the resource potential of the region and is the base for the definition of realized full load hours and potential model investments in the region. The location from where the wind speed time series is extracted is chosen in order to be representative in terms of wind characteristics: it is located in a central area and has an average wind speed with respect to the wind resource in the geographical region.
Since there is a total correspondence between Balmorel wind areas and Balmorel regions, from now on the two terms will be used equivalently when talking about wind modelling.

The wind resource in a certain Balmorel wind area is described by three parameters:

- **Wind speed time series**: a wind speed serie of 8736 values (hours), expressed in m/s.
- **Height**: height at which the time series is defined, expressed in m. It is used to calculate the wind speed at different heights.
- **Shear factor**: a dimensionless parameter which describes how the wind shear profile develops with height. It depends on the condition of the site in terms of roughness and obstacles.

Scaling height of wind data

Wind speed is generally expressed at 10m above the sea level. The hub of the turbines is normally located at much higher heights (50-150 m). As a consequence, the wind speed has to be extrapolated to different hub heights. There are two main analytical approaches used for the extrapolation, which in general shows equivalent results: the logaritmic law and the power law [90].

In the model, the power law is implemented due to its simplicity and widespread use both in academia and industry. It is an empirical equation given by:

$$u_2 = u_1 \cdot \left(\frac{h_2}{h_1}\right)^{\alpha} \tag{8.1}$$

where u_1 is the wind speed at the height $h_1$of the time series defined for the wind area, u_2 is the wind speed at the new height h_2 and α the wind shear factor.

Likewise the wind speeds, the shear factor used for the study is an average value estimated based on wind speed at 10 and 100 m from Vestas Mesoscale model and it is defined in the same locations as the wind time series. It spans from 0.07 to 0.11

in offshore locations and from 0.14 to 0.19 in onshore areas.

The use of logarithmic law was excluded because more detailed data about the roughness of terrain would be needed and the uncertainty about the improvement would probably not outweigh the added complexity.

Wind technologies - Aggregated power curve

The model is configured so that it is possible to implement different wind technologies. For each technology, technical aspects such as power curve and hub height, as well as costs are expressed.
A general distinction of technologies is based on whether the technology represents historical capacity or future additions and this is reflected as well in how the power curve is modelled. In practice:

- **Historical technologies**: they describe wind turbines already installed in the system. Characteristics and costs are based on realized data. One specific technology for each country/region is defined and no investments in these technologies is allowed in the model.

- **Future technologies**: they represent options for future installations and they are categorized based on their specific power. These are defined universally across the countries in the model and represent the only option for installations in future years.

Since the technologies implemented 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 represent 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 are determining the different shape of the aggregated power curve compared to the one from a single turbine:

- Technological mix: a large range of turbine models are installed in the system and each of them have a different production at the same wind speed
- Spatial averaging of production: turbines are spread in the wind area considered, 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

Some large scale projects [91] and publications [92] have been focusing on the regional aggregated power curves, but no formal approach is present in literature.
Based on different input and sources, an original approach to power curve aggregation has been developed.

In a general basis, the equation implemented in the model to describe the aggregated power curve is a modified logistic function:

$$P = \frac{\gamma}{1 + \mathrm{e}^{(-g \cdot K_w \cdot (u - M - \epsilon))}} \tag{8.2}$$

where:
- u: wind speed at hub height,
- γ: maximum power output reached in p.u.,
- M: wind speed at which the maximum growth is reached,
- g: maximum slope of the logistic curve,
- K_w: smoothening parameter to take into 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 technology. In addition, the hub height of the technology is defined as well and it represents the height to which the wind speed is extrapolated.

Different principles and approaches are used for the identification of the right parameter in case of historical and future technology.

The main idea for the difference is that for the existing turbines, data related to hourly and total realized generation in the region is available for every region in the model. As a consequence, it is possible to estimate the parameters and calibrate them to match historical generation.
On the other hand, no data regarding the total generation from the deployment of a certain wind technology across a region in the future is available. A dedicated procedure to create an aggregated power curve is therefore developed taking into account the aforementioned effects.
In the next two sections, the two different approaches are described.

Figure 8.3 shows a schematic representation of how total generation in a certain hour for a wind area in Balmorel is calculated by summing the contribution from both historical and future technologies.
The subscripts for the parameters in red specify whether the parameter is defined for a technology (T) or a wind area (A).

8.5 Historical technology curve fit

Given the availability of hourly data of wind production, the parameters representing the aggregated power curve for pre-existing wind in each wind area are chosen to fit historical duration curves and full load hours.

Specifically, given one time series in input for the wind speed in the year 2001 and one for the realized production, the optimal parameters of the logistic function will be chosen to minimize the difference between historical duration curve and duration curve resulting from the aggregated power curve.

For historical technologies the equation is reduced to:

$$P = \frac{\gamma}{1 + \mathrm{e}^{(-g \cdot (u - M))}} \tag{8.3}$$

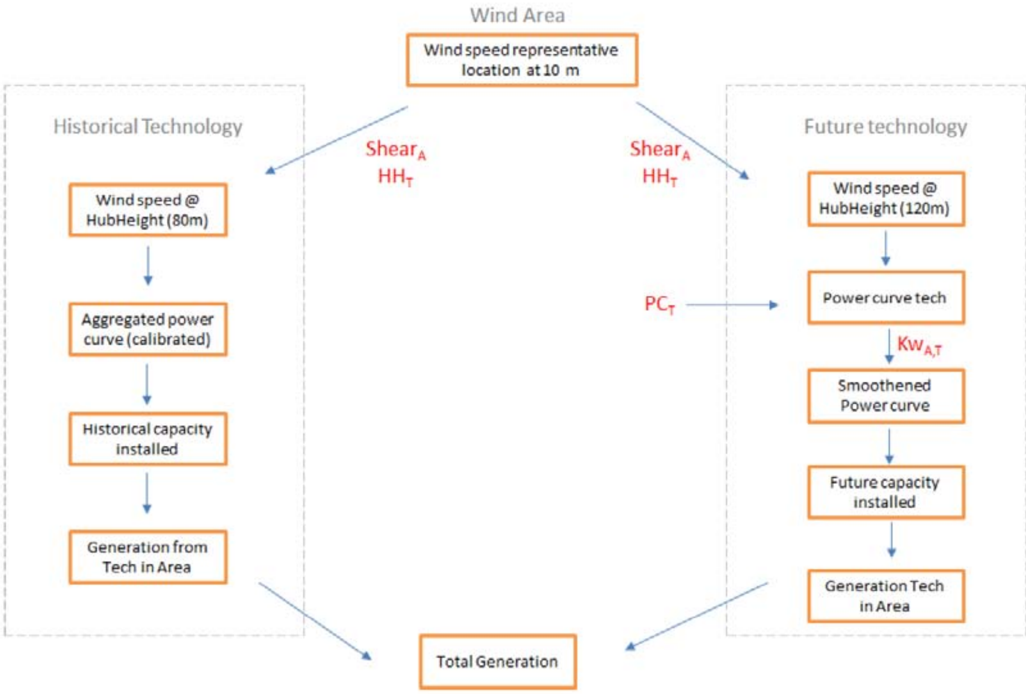


Figure 8.3: Flow diagram describing the conversion of wind speeds into wind generation, as a sum between historical capacity and new installations. (PC: power curve; K_w: smoothening parameter)

Parameters γ, g and M are the ones subject to calibration and ϵ is equal to zero in this case.
The historical data used for the calibration should be as recent as possible, in order to represent the variability and production of the turbine models and technology actually in use. On the other end, to avoid the choice of specific wind conditions when calibrating historical capacity, the ideal is using a normal wind year. Based on the wind energy index [93], 2015 was a very windy year (index 1.13), while in 2014 the index was 1.00.
For this reason, 2014 wind generation duration curve is used to calibrate historical capacity.

While calibrations for every country were already present in the model, they have been found in general not well calibrated and based on old data. As a consequence, given the framework of the analysis, German and Danish wind technologies for each wind area have been updated.

As for the normalization, in order to obtain the duration curve in *per unit*, the production is divided by the average of the capacity at the beginning and end of the year, to correct for the new additions along the year. This is very important for Germany due to the large amount of wind installed in the last few years.

Denmark Historical data for Denmark is accessible in the market data section of Energinet.dk [1] and the total onshore production is available with hourly resolution.

Since no separated time series of onshore production are available for east and west, the same technology is assumed in both the regions.
The calibration is done to find the power curve parameters which, applied to the two wind speed profiles in East and West Denmark and summing the two contributions, give the minimum difference with the total onshore duration curve.

Germany Data for Germany has been downloaded from ENTSO-E Transparency platform [25]. The wind production hourly data for onshore is available per TSO area. As it can be seen from Figure 8.4, the four TSO areas are different from the regions modelled in Balmorel. As a consequence, TSO profiles are allocated as shown. Even though the profiles are allocated to regions which do not exactly match the areas they represent, it has to be taken into account that the shapes of the duration curves are generally not so different, and that for TenneT area most of the turbines are installed in the north west and much less in the south, thus reducing the error in the assumption. On the other hand, the parameter γ, representing the maximum value of production reached within a region in p.u., could deviate from reality due to the allocation of regions.

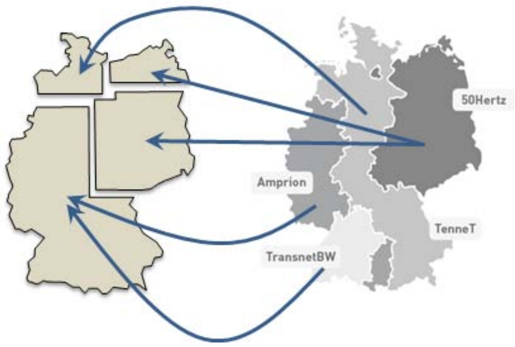


Figure 8.4: Allocation of German TSO areas to Balmorel regions.

The result of calibration for 50 Hertz region is shown in Figure 8.5 as exemplification. On the left, the power curve with the resultant parameters is shown, while on the right the comparison of the two duration curves, historical and modelled, is presented.

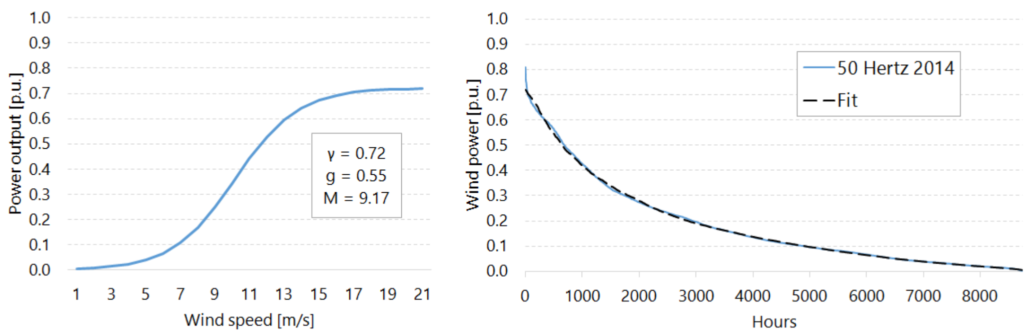


Figure 8.5: Example of historical calibration for Nort Easth Germany region.

8.6 Smoothening of the power curve for future technologies

Specific power classes and respective power curve

Three scenarios for specific power are part of the analysis, namely Sp200, Sp300 and Sp400. The power curves to be used in input for each of these scenario have to be selected.

An analysis of power curve data from a variety of sources [47], [48], [94], which all derivate the data from manufacturers data-sheets, was carried on. Figure 8.6(a) shows data normalized in *per unit* (p.u.) for a number of commercial turbines from different manufacturers, which SP span from 196 W/m^2 to 472 W/m^2. The trend is clear, the lower the specific power, the earlier the power reaches its nominal value (1 p.u.), meaning that the rated wind speed is lower.

For each class of SP, one turbine is chosen as representative. The three turbines selected, Gamesa G114 (200 W/m^2 class), Vestas V112 (300 W/m^2 class) and Siemens SWT 2.3-82 (400 W/m^2 class), which are then used in input to the analysis, are shown in Figure 8.6(b).

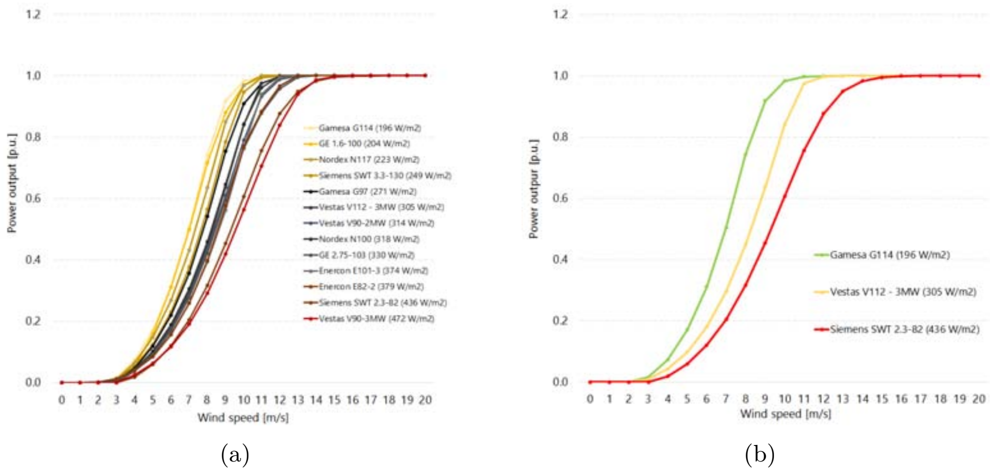


Figure 8.6: Power curves for a number of commercial turbines **(a)** and three power curves selected for the SP scenarios **(b)**.

Smoothening procedure

For future installed capacity of different technologies, a fit is not possible due to the lack of realized data. Moreover, the aim of the study is comparing different technologies in terms of specific power and hub height. Therefore, a need to understand effect of regional aggregation for certain technologies surges.

The question to answer is the following: *How does a fleet of turbine with a certain specific power and distributed on a particular geographic region performs in terms of total production?* And more: *How to represent this effect on an aggregated level,* *suitable for the modelling setup introduced?*

In order to answer these questions, the reference power curve from manufacturers describing a certain technology will be smoothened to take into account the effects of regional aggregation.

A rough method to produce a *Multi-turbine power curve* is described in [92], which suggests to use a convolution between the power curve for a single turbine and a normal distribution of speeds, which standard deviation is calculated based on the size and turbulence of the area.
This method has been used and developed in other publications assessing production of aggregated turbines [79] [82]. However, those publications focuses on a wind farm or multi-farm level and do not focus on entire regions.

Due to a lack of a formalized approach in literature which is suitable for this study, a smoothening procedure has been designed and developed based on the ideas expressed in [92]. The attempt is to find a balance between the need to keep the simplicity and the reduced computational effort in the model on one side, and an accurate description of the potential output from a geographically distributed wind turbine fleet on the other side.

The following steps explains the idea behind the process of smoothening:

1. Power curve with a certain specific power selected
2. Wind speeds time series for multiple locations in a region chosen from CFSR-NCEP renalaysis database, together with a reference wind time series for a representative location
3. *Total generation* calculated as sum of generation from the turbine in each location in the region
4. *Total generation* plotted (scatter-plot) with respect to the reference wind time series
5. Calculation of the standard deviation which, convoluted to the original power curve, minimizes the total hourly difference between *Total generation* and generation from the smoothened power curve applied to reference wind time series

The resultant curve is the aggregated power curve which, applied to the reference wind time series, better fits the generation from the turbines spread across the region.

Example An example of the aggregation process is presented for Western Denmark, considering a turbine Gamesa G114 (200 W/m^2). The map in Figure 8.7 shows the seven locations where a wind speed time series has been extracted from the satellite reanalysis database. The reference wind location in this case is Herning, chosen for its central position and relatively flat surrounding terrain.

Figure 8.7: Locations from which wind speed time series are extracted. In blue, the reference location (Herning) is shown.

One turbine is placed in each site and the production is calculated. Then, all productions are added to calculate the *Total generation*. This generation time series is then scattered with respect to the wind speed in Herning and the optimal standard deviation is calculated.
The diagram in Figure 8.9 shows the steps, while Figure 8.8 compare the original power curve (red) to the one resulting from the smoothening procedure (black) and shows the *Total generation* with respect to the wind speed in Herning (blue scatter plot). The resultant standard deviation is $\sigma = 2.064$, meaning that to calculate the smoothened power curve a normal distribution of wind speeds with this standard deviation have to be convoluted to the reference power curve.

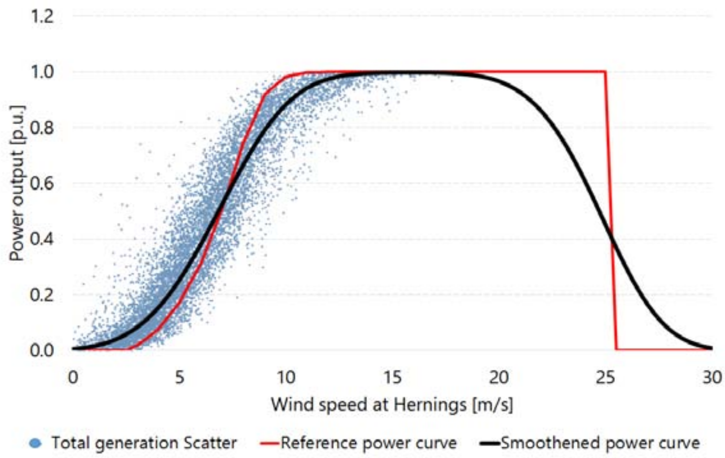


Figure 8.8: Results from the smoothening procedure for Western Denmark.

In order to understand the importance of this smoothening procedure, the duration

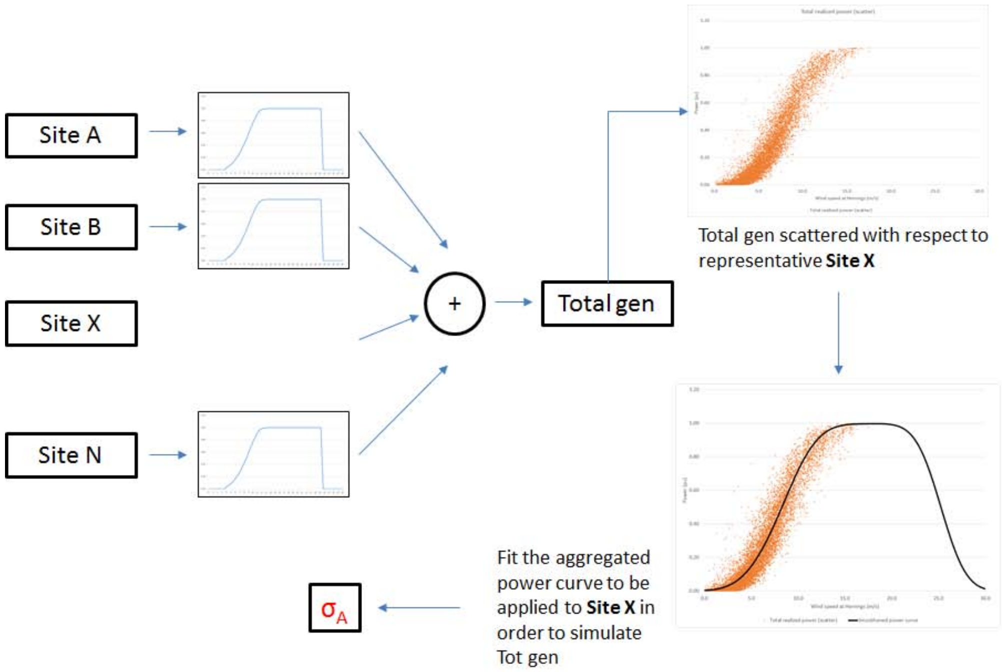


Figure 8.9: Visualization of the idea behind the process of power curve smoothening for future technologies.

curves of annual wind production resulting from the two power curves applied to the wind speed in Herning are displayed in Figure 8.10 and compared to the *Total generation*. In other words, the comparison is between using a reference power curve from manufacturers to directly represent an aggregated power curve, or using the method described to calculate the smoothened aggregated regional power curve.

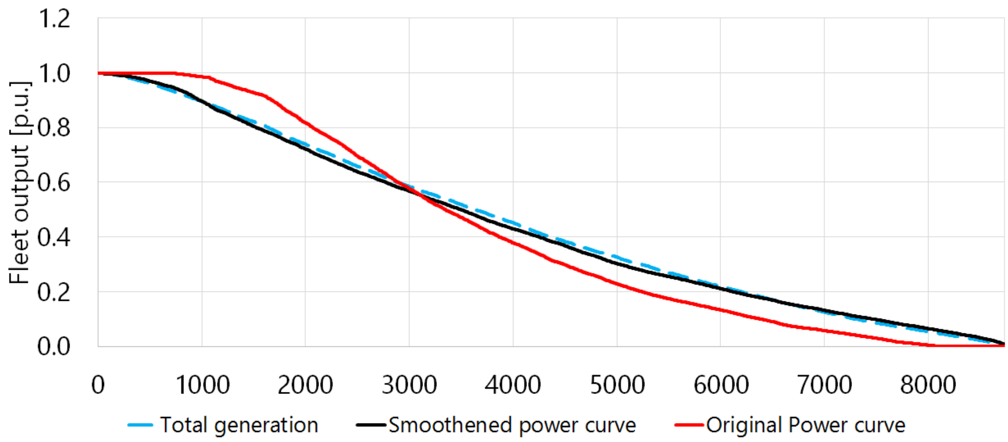


Figure 8.10: Comparison of duration curves from reference power curve, smoothened one and *Total generation*.

As can be seen the smoothened power curve better represents the output of the distributed fleet and its shape is much closer to duration curve of wind production from real data, i.e. no plateau at rated power is present.

Model implementation Implementing the smoothened power curve in the model as resulting from the previous method would be computationally inefficient and would involve a lot of coding, due to the need of a look-up table.
Instead, based on the same idea just expressed, the smoothened power curve is represented with a logistic function, in order to keep the same model structure pre-existent in Balmorel and reduce complexity and computational time. This means that the effect of the convolution of normal wind speed distribution to the reference power curve is modelled with a parameter in the logistic function, namely K_w, which substitutes the standard deviation above mentioned.

The equation for logistic curve describing future technologies becomes:

$$P = \frac{1}{1 + \mathrm{e}^{(-g \cdot K_w \cdot (u - M - \epsilon))}} \tag{8.4}$$

The steps which leads to the estimations of the parameters in the equation are the following:

1. Reference power curve from producers specification corresponding to certain specific power selected
2. Parameters g (growth reate) and M (maximum growth) chosen to represent the reference curve with a logistic function
3. Wind offset considered (parameter ϵ) to express "real" production compared to the one from reference power curve
4. Wind speeds time series for multiple locations in a region chosen from CFSR-NCEP renalaysis database
5. *Total generation* 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 K_w, which describes the modification of the growth rate to take into account the smoothening, in order to minimize the total hourly difference between *Total generation* and wind production from the smoothened power curve applied to reference wind time series

Figure 8.11 shows a summary of the process.

The smoothening in the cut-off part of the curve, for very high wind speeds is not implemented. This would add at least two more parameters for each technology and the complexity and computational effort is not worthed, due to the negligible number of hours at high wind speeds for onshore wind.
In case future studies would focus on offshore wind, where the wind speed reaches higher values, the cut-off behavior of aggregated fleet should be taken into account.

An interesting result is that the smoothening of the power curve does not only depend on the area considered, but also on the technology. Since the lower the specific

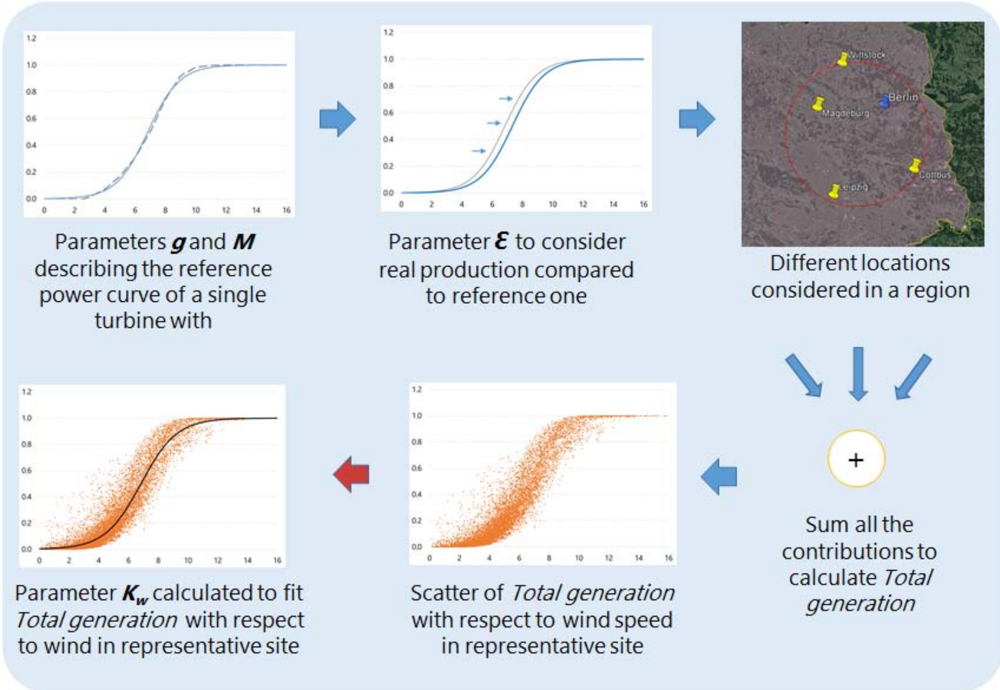


Figure 8.11: Process carried out to calculate the parameters of the logistic function which describes the smoothening of the power curve.

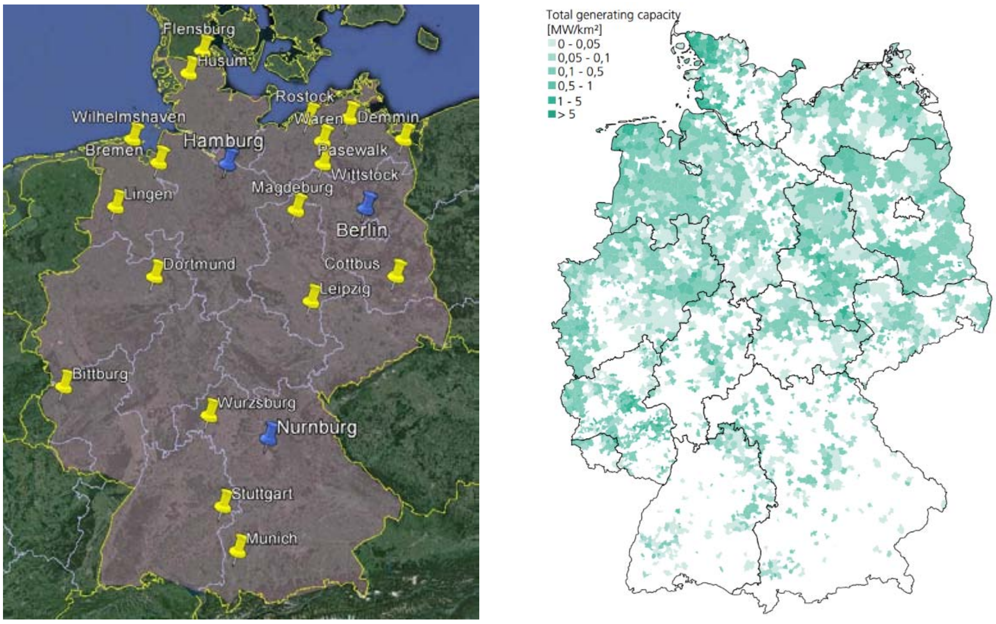
power the more steep the power curve is, a deviation from the wind speed in the reference location can cause a large variation of power output, ultimately resulting in a more smoothened power curve.

For this reason, the process described is repeated for every combination of SP technology and Balmorel region to obtain the parameters which define the regional aggregated power curves to input to the model.

Due to time and effort needed, the process has been carried on for the four regions of Germany, since focus country for this study and the two regions of Denmark, due to its very high wind penetration and potential impact on results. As for the other European countries, aggregated power curves based on Germany and Denmark smoothening has been assigned based on the size of the region.

Depending on the extension of the region considered, between 4 and 7 locations have been chosen to calculate the smoothening. Locations for Germany have been selected based on the wind turbine density described in Figure 8.12(a). In addition, the representative locations of each Balmorel region are highlighted in blue in Figure 8.12(b).

Parameters 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 8.1.



(a) Locations chosen (b) Distribution of turbines

Figure 8.12: **(a)**: Locations chosen for the extraction of wind speed time series used in the smoothening process in Germany. **(b)**: Density of turbine installations in Germany. Source: [74]

Parameter	**200 W/m^2**	**300 W/m^2**	**400 W/m^2**
Growth rate g	0.955	0.810	0.623
Max growth M	6.84	8.08	9.46

Table 8.1: Parameters g and M defining the power curves of the different technologies in terms of specific power.

The parameter ϵ, an offset on 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 which all contributes to a reduction in the realized output. A visualization of the effect is shown in Figure 8.13, based on simulations carried on in [82].
A value of $\epsilon = 1.2\ m/s$ 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 [82] and [95]. Furthermore, the offset is equal to the one used in [96] and close to the one, equal to 1.27, used in [79].

Finally, the values of K_w, computed for the various regions of Germany and Denmark are summarized in Table 8.2.
A lower value of K_w is related to a more smoothened 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, it is possible to note that for larger regions such as Western Denmark or Central-Southern

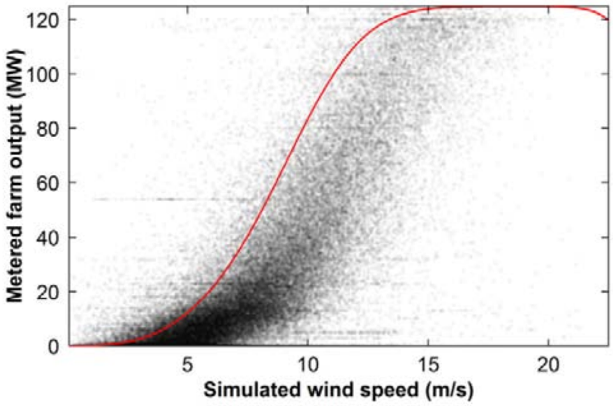


Figure 8.13: Metered output from a farm compared to the theoretical power curve (red), as a function of the simulated wind speed at the site. Source: [82]

Balmorel region	200 W/m^2	300 W/m^2	400 W/m^2
DE_{NW}	0.781	0.820	0.887
DE_{NE}	0.823	0.821	0.898
DE_{ME}	0.868	0.880	0.952
DE_{CS}	0.671	0.720	0.840
DK_W	0.657	0.711	0.815
DK_E	0.790	0.812	0.876

Table 8.2: Parameter K_w for the different combinations of SP and Balmorel regions.

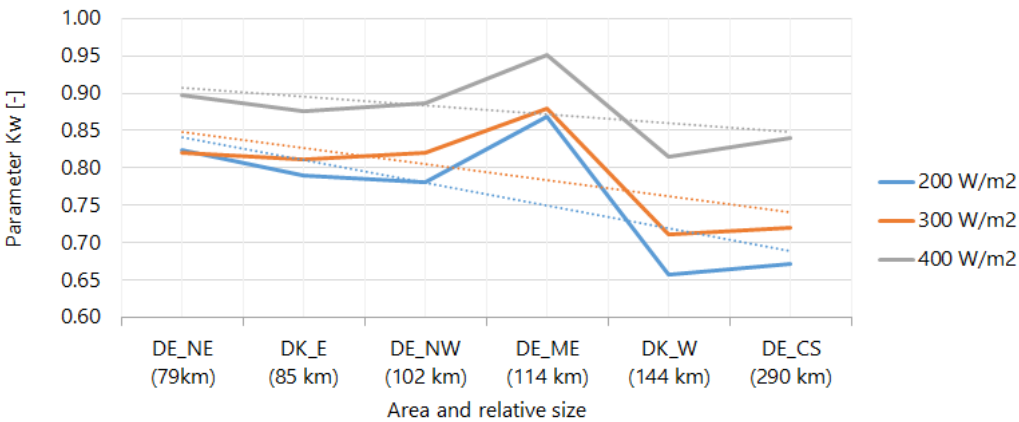
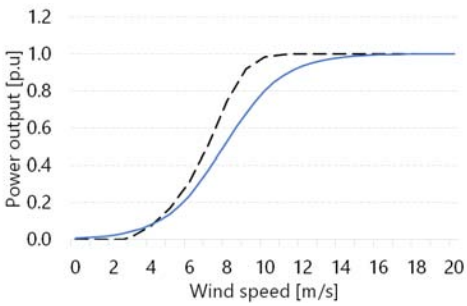


Figure 8.14: Resultant values for K_w for different areas and SP values.

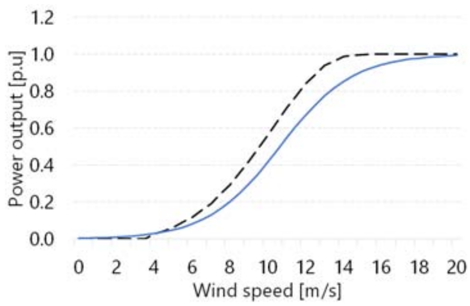
Germany, the parameter is lower than for smaller area, where the correlation of wind speeds is supposedly higher.
Moreover, as already mentioned, the lower the specific power, the more the aggregated power curve is smoothened. Indeed, lower specific power is associated to

steeper turbine power curve and the result is higher variation in the power for locations around the reference one. These observations are graphically presented in Figure 8.14, were the parameter K_w is shown for different specific powers and area sizes. The area size is expressed as the radius of the minimum circle containing the observation points.

An example of two aggregated power curve for 200 $W/m2$ (a) and 400 W/m^2 (b) compared to the respective reference ones is showed in Figure 8.15.



(a) 200 $W/m2$



(b) 400 W/mr

Figure 8.15: Aggregated PCs (blue-solid) compared to reference ones (black-dotted), for two specific power levels.

8.7 Limitations of the method used

Both the general wind modelling and the method developed are meant to describe in a simple way the effects of turbine aggregation and being to some extent empirical certainly hold limits and inaccuracies. Beside the general limitations given by the high level representation of a system model like Balmorel, it is important to mention:

- No consideration of complex terrains and roughness when extrapolating speeds at different heights
- Importance of location chosen as representative, since only one time series is representing the region or country
- Limited number of locations chosen for each region
- Even capacity distribution inside the regions considered when calculating smoothening
- Missing correction of the biases given by reanalysis data when calculating the smoothening of the power curves
- Implementation of smoothened power curve calculated with renalysis data in a model which uses Mesoscale data
- Cut-off at high wind speeds not modelled

All in all, these limits are considered acceptable and part of the trade-off between accuracy and simplicity and they could always be addressed in future studies.

Part III

Results & Sensitivity

9

Results

This section describes the results of the simulations and analyses performed. All monetary results are expressed in real terms in 2015-€.
Firstly, general results for the entire system and for Germany, such as installed capacities and annual production will be for the central scenario Sp300, in order to characterize the system conditions. Secondly, results for the specific power scenarios are presented in detail, starting with system results, followed by total costs assessment and value of wind results. Consequently, selected results for hub height scenarios are shown in a more concise way.
Indeed, as it will be shown, varying specific power of turbines showed more pronounced impacts on the system and markets than hub heights.

As already mentioned, most of the results will be shown for Germany, focus country of this analysis. However, as a comparison, selected results will be presented for Denmark, since it is the country with the highest wind penetration in Europe and it has been modelled more in detail than other EU countries.

9.1 General system results

System results for the entire geography represented are shown for the 300 W/m^2 scenario as central case.

Figure 9.1 expresses the total installed capacity in the entire system. The trend up to 2030 is an increased RES-E capacity and a gradual decommissioning of both nuclear and conventional plants. The largest decommissioning of fossil fuel plants takes place in 2020, first year in which the model can choose to dismiss capacity. This is the result of the lower capacity factors these plants can achieve in the market, due to the pressure of RES generators, which are dispatched first due to their lower marginal cost. It has to be noted that coal sees the largest reduction in the installed capacity, while natural gas is less affected.

The results for the annual generation (Figure 9.2) confirm this trend, with a reduction in the output of conventional plants and a sharp increase in RES-E generation.

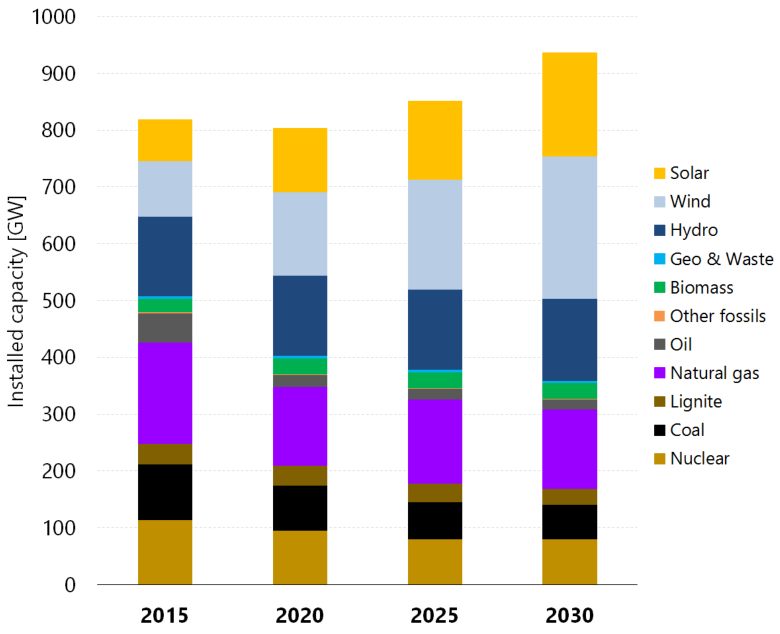


Figure 9.1: Evolution of installed capacity for the entire system, Sp300 scenario.

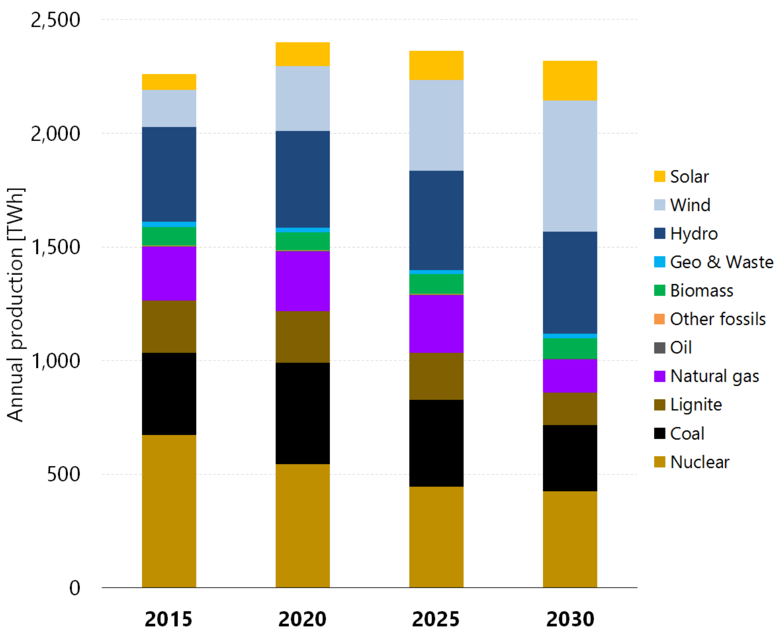


Figure 9.2: Evolution of annual generation for the entire system, Sp300 scenario.

Table 9.1 expresses the percentage of annual generation for each group of plants. The effect of nuclear decommissioning of Germany and the lower pace of reinvestments in other countries reduces the nuclear share from almost 30% in 2015 to 19% in 2030. Fossil fuels halve their generation in the 15 years span. On the other hand, RES

sees a very large increase in their output, which results in a share almost doubled by 2030.
While hydro power and biomass are almost constant throughout the years, solar and wind (VRES) are the key contributers to the RES development over time. In 2030, VRES production makes up 36% of the annual generation in the system studied.

	2015	**2020**	**2025**	**2030**
Nuclear	29%	23%	19%	19%
Fossil Fuels	40%	40%	34%	23%
RES	32%	38%	47%	58%
VRES [% total]	10%	17%	26%	36%

Table 9.1: Share of total generation per type of generators: Nuclear, Fossil fuels and RES.

German power system

When looking at Germany, the effect of nuclear phase-out and the large development in wind and solar are reflected in the installed capacity in Figure 9.3 (Sp300).
It can be noted that in 2020, first year in which investment and decommissioning are allowed, about 13 GW of Natural gas, 5.5 GW of Coal and 2.5 GW of Oil are decommissioned, meaning these plants were not profitable in the model. Being a model output, these results of decommissioning do not take into account if the pace is reasonable or not with a 5 years time horizon.

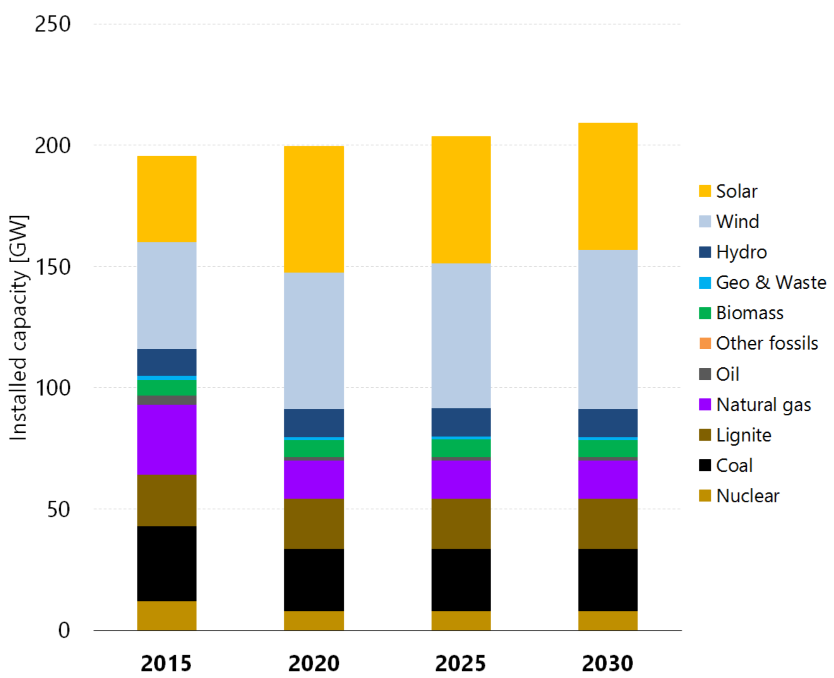


Figure 9.3: Evolution of Installed capacity in Germany in Sp300 scenario.

Wholesale electricity price

As mentioned in the model description, Balmorel performs an economic dispatch simulating the market closure every hour in each of the regions in the model. The resultant prices for each year and scenario can be visualized in a "heat map". Figure 9.4 shows an example of such a map, describing the prices in 2030 in the reference Sp300 Scenario. The lines connecting each model region represent the total annual electricity flow in TWh.

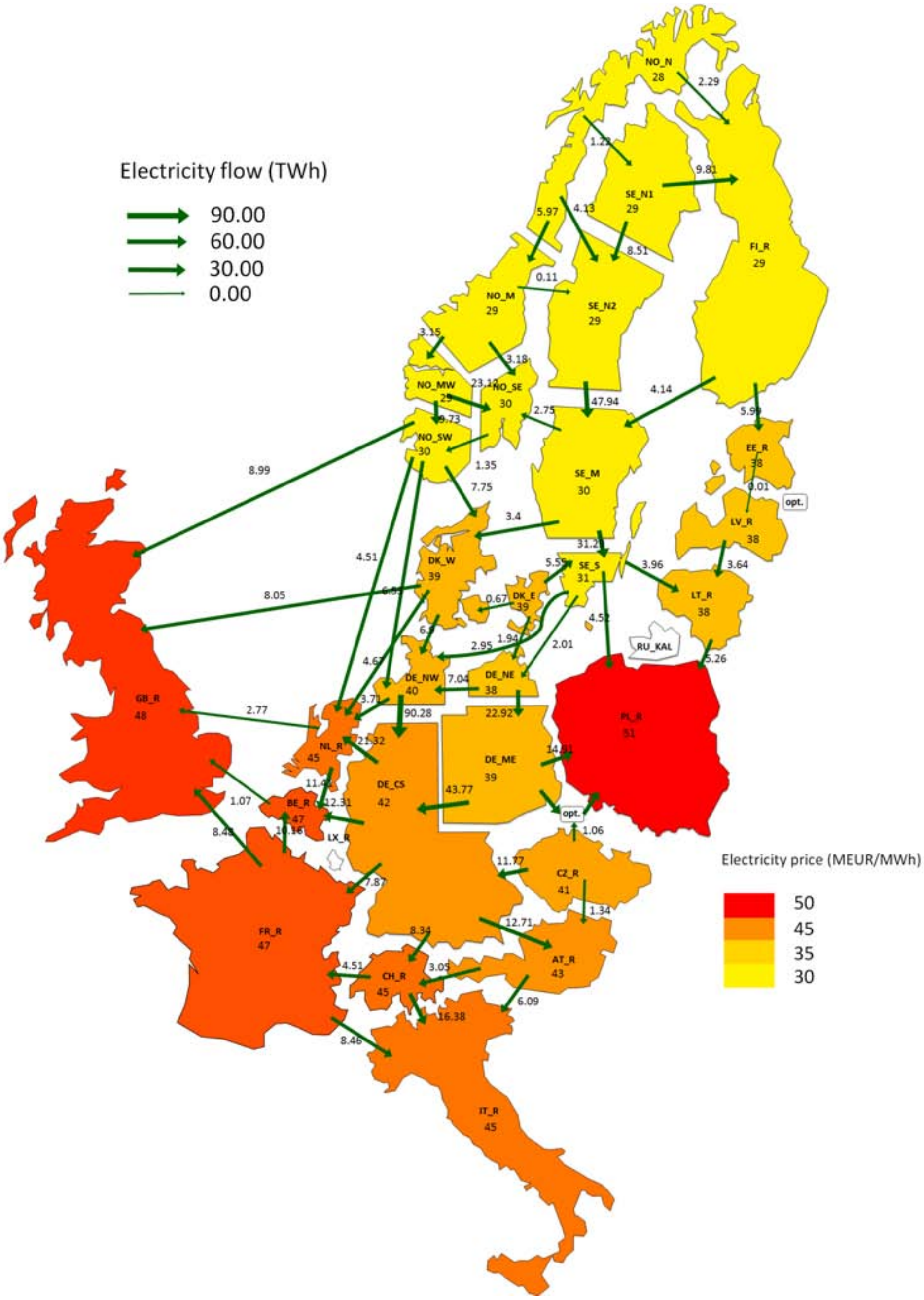


Figure 9.4: Map of average electricity prices in 2030 for Sp300 reference scenario.

9.2 Specific Power Scenarios - Sp200, Sp300 and Sp400

Variations in the annual power generation

The variation in the annual production per fuel from the reference scenario (Sp300) are shown in Figure 9.5 for Sp200 and Sp400.

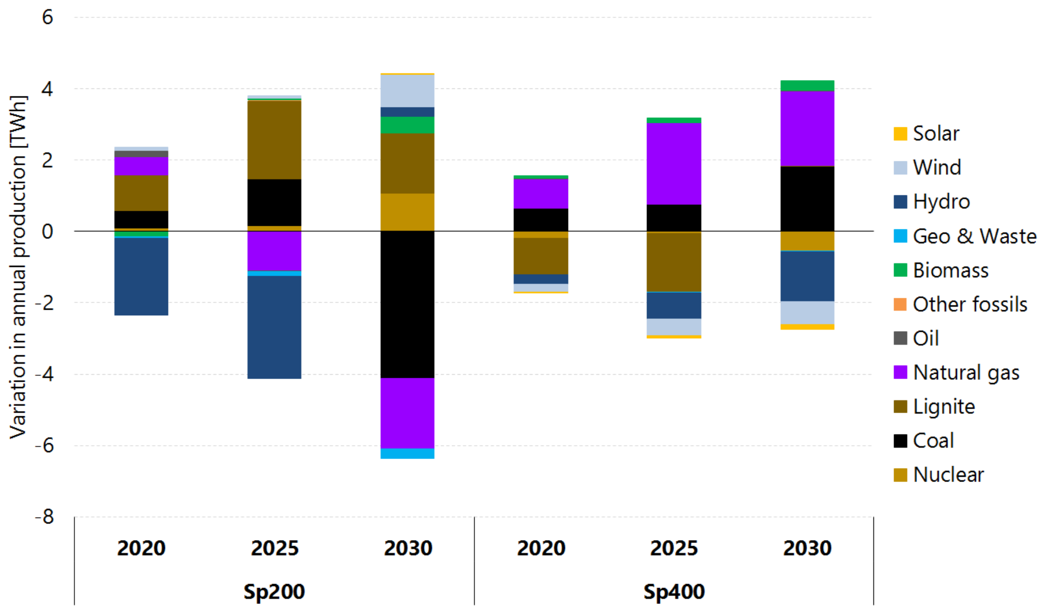


Figure 9.5: Variation of annual generation in Sp200 and Sp400 with respect to Sp300.

In scenario Sp200 there is a general tendency, especially in the long run, of increasing baseload generation (nuclear, lignite) and reducing coal and natural gas.
On the contrary, in Sp400, natural gas and coal generation are increased in every simulated year. Wind and solar generation are reduced in the scenario due to the curtailment which is taking place in hours of high VRES generation.

It has to be noted that, since an investment optimization was run for each scenario and year, there are variations of installed power across scenarios, which concur in the differences of power generation.

What can be observed in general terms, is a reduction of the total capacity in the system when reducing SP of wind turbines. The less volatile nature of the wind production enables the system to serve the load with less capacity. In particular it is the capacity of peak power plants to be displaced.

One note has to be added. In the figure, a change in the yearly hydro power production across scenarios is highlighted. This is a result of how hydro power in modelled in Balmorel, as explained in Section 7.2, and it is not directly related to the technology choice.

Wind installed capacity

In the different scenarios, the features of the wind turbines are changed in terms of power curves, resulting in a different production pattern.
The first implication of this difference regards installed capacity. Since the penetration level (i.e. the total wind production) is fixed across scenarios, changes in the hourly production are reflected in the required capacity to reach the specified target.

Table 9.2 shows the differences in the onshore installed capacity for the different SP scenarios in Germany. Historical capacity is the same across all scenarios and is reduced to 17 GW in 2030. On the other hand, new wind capacity varies a lot with the scenarios. The largest new capacity in the German system is deployed in the 400 W/m^2 scenario. With a lower specific power, the capacity is reduced sharply. In the 200 W/m^2 the capacity in the system is about 55% of the one in the 400 W/m^2 scenario, while in the 300 W/m^2 it is roughly 70%.

Over time, the absolute difference in the total wind capacity (historical plus new installations) is increasing due to the large investments in wind power and decommissioning of old capacity. The onshore wind capacity in 2030 is 55 GW in the 200 W/m^2 case and 85 GW in 400 W/m^2 scenario. In other words, reducing specific power in the new installations from 400 to 200 W/m^2, enables to provide in 2030 the same amount of wind generation with 30 GW less capacity.

			2015	**2020**	**2025**	**2030**
Historical wind capacity	[GW]		41	38	26	17
		200 W/m2	0	11	26	38
New wind capacity	[GW]	300 W/m2	0	15	34	50
		400 W/m2	0	21	47	69
Onshore wind share	[% dem.]		12%	19%	25%	31%

Table 9.2: Wind Power capacity in Germany: evolution of Historical and New installations for different scenarios, at the same wind share in terms of percentage of demand covered.

The lower capacity requirement at the same penetration rates is due to the larger amount of FLH (higher Capacity Factors) for low SP technologies.
As presented in Chapter 5, harvesting more power at lower wind speeds increases the capacity factors of the wind turbines. The resultant FLH in the simulations are shown in Figure 9.6.

The average values in Germany are 3607 FLH (CF=0.41), 2715 FLH (CF=0.31) and 1981 FLH (CF=0.23) for the 200, 300 and 400 W/m^2 technologies respectively. As it is possible to note, deploying turbines with a specific power of 200 W/m^2 results in almost doubled capacity factors compared to 400 W/m^2.
Looking at the capacity factors and installed capacity, some considerations can be expressed.

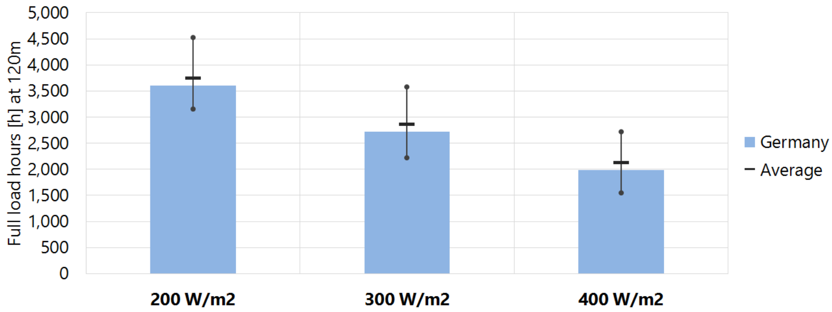


Figure 9.6: FLH for different SP at 120m hub height. Average values for Germany in blue, while the box and whisker express minimum, maximum and average values across the entirety of regions and wind conditions simulated in the model.

First of all, the total swept area of the new wind fleet is only 10% higher in the Sp200 scenario compared to Sp400. This means that an increase of 10% in the swept area drives a reduction to 55% of installed capacity.

Secondly, the number of turbines is reduced.
As expressed in Section 4.6, a certain specific power level can be reached either by reducing rated power with the same swept area, or by increasing diameter at the same rated power (or a combination of the two).

If we imagine that the SP reduction is coming from increased diameters, i.e. assuming the same turbine rated power for each scenario (2 MW), the number of turbines installed in Germany is equal to 5430 (Sp200), 7180 (Sp300) and 9680 (Sp400). Specifically, the three models would be 2MW-113m, 2MW-92m and 2 MW-80m.

On the other hand, if the same rotor is installed turbines across the three scenarios (113m), with capacities of 2, 3 and 4 MW respectively, the scenarios Sp200 results in a higher number of turbines.

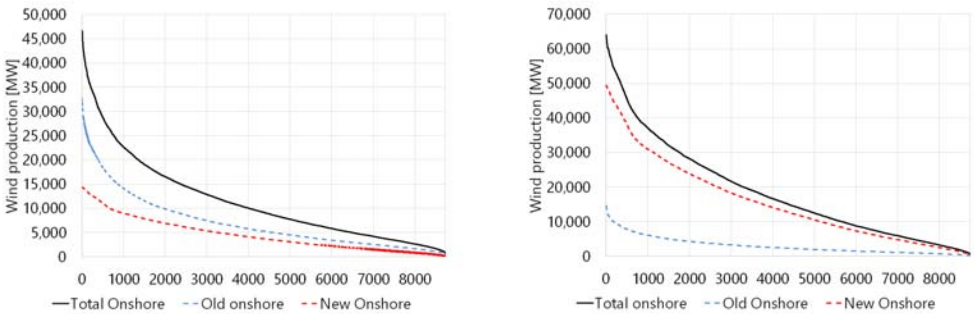
Finally, if we assume a rating of 2, 2.5 and 3 MW for the respective scenarios, the total number of turbines would be 5430 (Sp200), 5745 (Sp300) and 6452 (Sp400). In this last case, reducing SP from 400 to 200 reduces the number of turbines by 15.9%.

Wind power duration curves

Duration curve of onshore wind power, by definition, shows the number of hours over the year (x-axis) when the feed-in from onshore wind turbines to the grid was above a certain power (y-axis). Moreover, the area under the curve represents the total annual electricity production from onshore wind. As a consequence, it is an indication of how wind generation is distributed throughout the year and can underline how the hourly wind-infeed differs.
It depends both on the wind conditions and the wind technology. Since the scenarios share the same wind speed time series in input, any variation of the duration curve

is due to the effect of the technology variation.
The changes in the duration curve over time are shown both with respect to its composition for one scenario (historical vs. new capacity), and across scenarios.

Change of composition Due to the decommissioning of historical capacity and the continuous addition of new turbines, the shape of duration curve is changing over time.
Figure 9.7 shows the development of the duration curve over time for the central scenario Sp300. The same result holds for the other scenarios. In 2020, the historical capacity is making up the vast majority of wind power therefore the shape of the total onshore duration curve resembles the one of old installations (Figure 9.7(a)). In 2030, it is the newly installed wind that mostly affect the shape of the duration curve (Figure 9.7(b)) and, since it is different in each senario, larger differences are expected over time.



(a) Wind duration curve in 2020 (b) Wind duration curve in 2030

Figure 9.7: Change in the duration curve shape over time due to decommissioning and new investments. Scenario Sp300.

Change across scenarios Given the composition of the duration curve, it is interesting to look at the difference between the total onshore wind duration curve across SP scenarios.

Figure 9.8, 9.9 and 9.10 express the different wind duration curves for the total onshore fleet in Germany for years 2020, 2025 and 2030 respectively.
It is here possible to see the effect of reduced capacity and higher capacity factors. Higher capacity factors enables to produce the same wind energy with less capacity installed, therefore reducing the peak in the total onshore wind fleet.
As a consequence, the difference across scenarios is highest in the 2000 most windy hours. Indeed, since the total generations have to be the same, so has to be the area below the three curves. As a result, decreasing the specific power corresponds to a slight increase in the production in the 6000 lowest windy hours and a sharp decrease in the production during the 2000 most windy hours. These hours are the ones mostly related to integration issues, such as merit-order effect and transmission expansion. The consequence of a reduced peak in the wind infeed has positive system effects. Indeed, it could enhance wind integration both in terms of reduced market impact and lower need of costly transmission network, by reducing the need for large

export capacity in hours of high wind.
Later in the chapter it will be shown how this reduction in the onshore wind peak affects the resultant wholesale electricity prices.

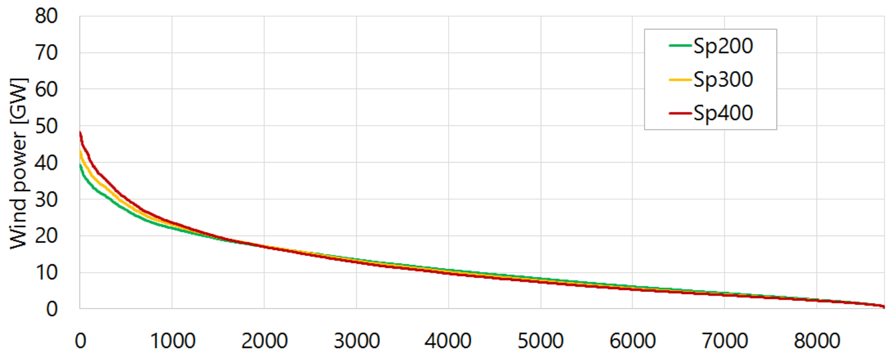


Figure 9.8: Onshore wind in Germany. Change in the duration curve across scenarios in 2020.

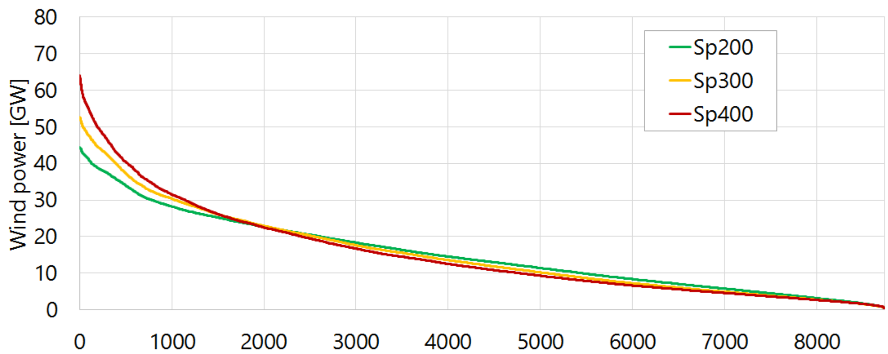


Figure 9.9: Onshore wind in Germany. Change in the duration curve across scenarios in 2025.

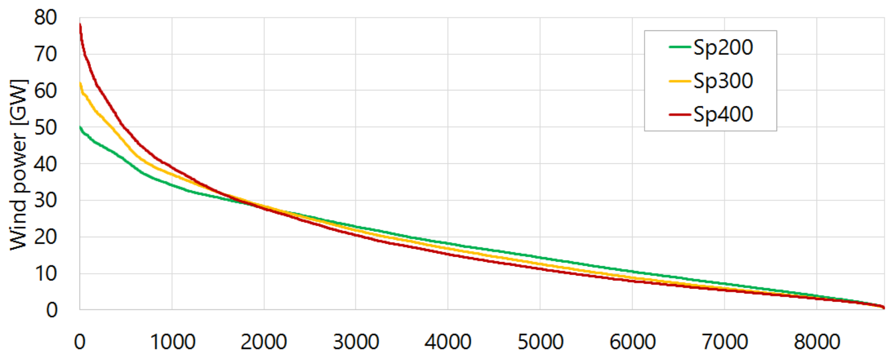


Figure 9.10: Onshore wind in Germany. Change in the duration curve across scenarios in 2030.

Residual load duration curve

Another way to visualize the positive effect on system of deploying lower specific power turbines is by looking at the residual load duration curve.
The residual load duration curve is calculated by subtracting hourly total wind generation from hourly demand data. Normally, to calculate residual load all the VRES are detracted, but in this case solar is excluded for ease of visualization and to later calculate capacity credits.
Figure 9.11 shows the original load duration curve for Germany in 2030 and the respective residual load duration curves for the three scenarios.

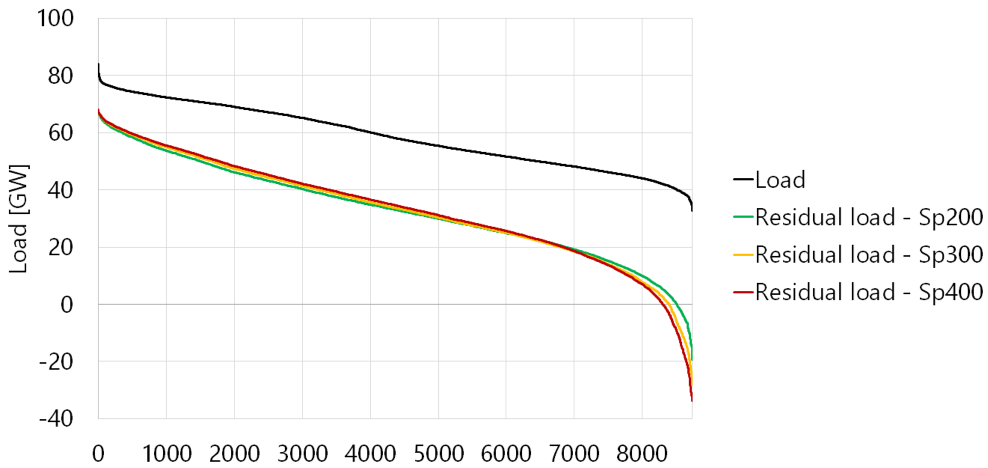


Figure 9.11: Residual load duration curve in 2030 for the three SP scenarios.

As underlined by [97], increasing shares of VRES have a strong influence on residual load, resulting in temporary situations of surplus in the renewable generation. As a consequence, integrating growing amounts of wind and PV into the power system increasingly requires the application of dedicated integration measures, among them different types of energy storage, demand-side measures, network expansion, flexible thermal back-up plants and renewable curtailment.

As can be seen in Figure 9.11, lower SP makes the residual load easier to serve, by increasing the room for baseload and decreasing the steepness of the curve. This explains the results anticipated in Section 9.1, where an increased generation from baseload, namely lignite and nuclear, was underlined in the Sp200 scenario.
Moreover, as will be shown in the next subsection, the peak of the residual load is slightly reduced.
The combined effect of a more flat curve (increase in baseload power) and a reduced peak, explains the general reduction in the installed capacity of the system as well as why this reduction comes mainly from less peak generators installed. As will be shown, this is reflected in the total system costs.

Another effect is the reduction in renewable surplus, in terms of both magnitude and amount of hours. In particular, the hours with a negative residual load are reduced from 439 in the Sp400 scenario, to 343 in the Sp300 and down to 232 in the Sp200. If comparing the two extreme SP scenarios, it corresponds to halve the

negative residual load hours.
In absence of other measures such as storage and demand response, which are not modelled in detail, this reduction of the RES surplus potentially reduces the hours in which curtailment needs to take place.

Capacity credit of onshore wind

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 [98]. Both onshore and offshore wind are considered. When looking at Figure 9.11, the peak reduction is the difference between the load and the residual load of a single scenario at $x = 0$.

$$CC_w = \frac{max(load) - max(resload)}{P_{wind}} = \frac{peak\ reduction}{P_{wind}} \tag{9.1}$$

It represents the percentage of total wind power that can be considered as firm capacity and thus contributes to system security [99].

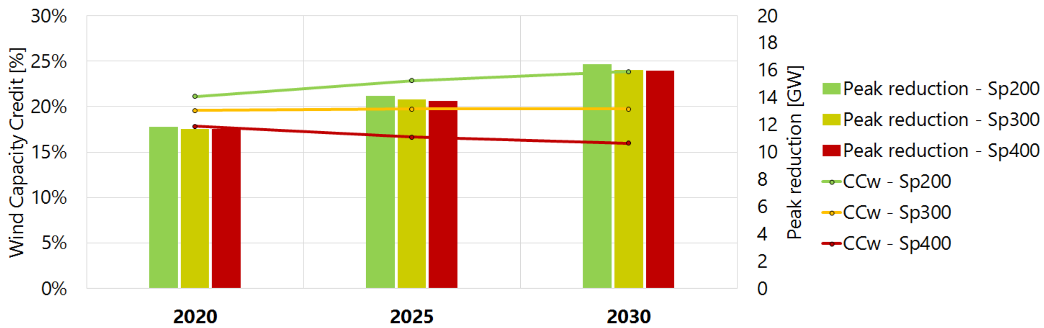


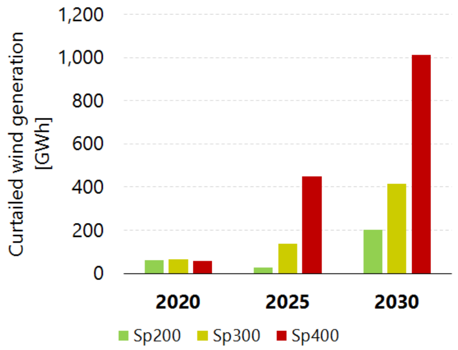
Figure 9.12: Capacity credit (left axis) and reduction of the peak capacity (right axis) in the different SP scenarios.

Resultant CC_w in Figure 9.12 confirms previous results presented in [99], i.e. increased capacity factors and improved wind technology lead to higher capacity credit across all the range of the wind penetrations.
Nevertheless, there is another interesting insight: the use of advanced technology in terms of specific power not only limits the reduction of the capacity credit, but in the extreme case of scenario Sp200 the capacity credit is increasing over time, regardless of the increment in installed capacity and wind penetration.
On the other hand, the difference across scenarios in terms of peak reduction (secondary axis in Figure 9.12) is not very large and for 2030 is it is around 16 GW. This can be explained by the fact that the peak in the residual load duration curve is taking place in hours of low wind speed. Reducing SP increase production in intermediate wind conditions and much less in the low wind hours.
As a consequence, the higher capacity credit of the reduced SP scenarios is mainly due to a lower wind installed capacity, which ensure a higher level of firm capacity in terms of percentage value.

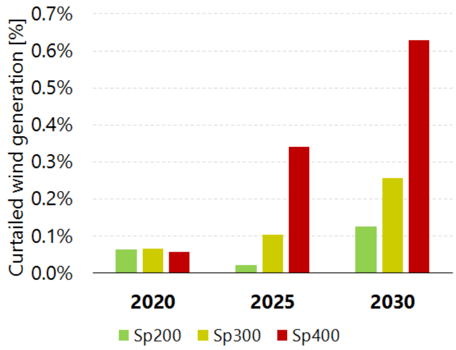
Finally, it has to be underlined that this result can only be considered as approximate and illustrative. Indeed, more precise metrics to assess the capacity value of wind in a system exists, which relies on probabilistic and more rigorous methodologies. Among other things, different wind years should be considered, while this study focuses on a normal wind year only. For a review of these methods see [100].

Wind Curtailment

Given the intrinsic characteristics of low SP technologies, which have a much smoother generation profile and less spikes in the wind production, the curtailment of wind power is reduced. Figure 9.13 shows the different amount of onshore wind power curtailed annually in Germany across the three scenarios.



(a)



(b)

Figure 9.13: Annual curtailment of onshore wind in Germany, expressed in GWh (a) and percentage of onshore wind generation (b).

The results show that not only reducing the specific power largely reduces the curtailment in absolute terms, but it is interesting to note that in the Sp200 scenario the curtailment is reduced between 2020 and 2025, due to the effect of the increased interconnection in the North-South corridor in Germany. In contrast, in the two scenarios with higher SP, the benefit of the additional NTC is outweighed by the increase in the installed capacity.

As for offshore wind in Germany, it has to be underlined that in 2030, curtailment in Sp200 is 141 GWh, while in Sp400 1,721 GWh (12 times the one of Sp200). Therefore, reducing SP has an impact in the curtailment of offshore wind as well.

Wholesale electricity price development

In average terms, prices are not affected so largely by the wind scenario. Figure 9.14 expresses the development of average prices in Germany throughout the modelled years and in the three SP scenarios. Note that since Germany is constituted by 4 price zones in the model, the annual average price in each region is weighted with the annual electricity consumption of the region.
The lower the specific power, the higher the average electricity price results. To give an idea of the magnitude of the change, in 2030 average annual prices are equal to 41.83, 41.70 and 41.38 €/MWh respectively (Sp400, Sp300 and Sp200). This lower price change is mostly due to less hours with negative prices, more than to a difference in the installed capacity in the system.

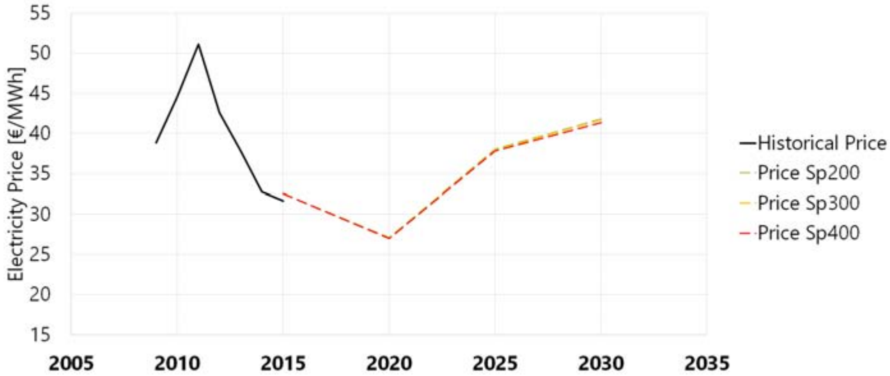


Figure 9.14: Development of annual average electricity prices in Germany (consumption-weighted across regions).

Price duration curves

More interesting than the average wholesale electricity prices is the structure of the price duration curve, since it better reveals the changes driven by different wind technologies in their interaction with the market.
Price duration curve describes the number of hours (x-axis) in which a certain electricity price (y-axis) is exceeded, therefore represents all the hourly prices in a year sorted in descending order. As explained in Chapter 3, wind directly affect the market causing the merit-order effect.

Figure 9.15 shows the price duration curves for the three SP scenarios in the region DE-NW for the year 2030. The specific region is chosen due to the high wind capacity installed, nevertheless both the structure and the differences across scenarios are very similar in the other three German regions and in other countries as well.

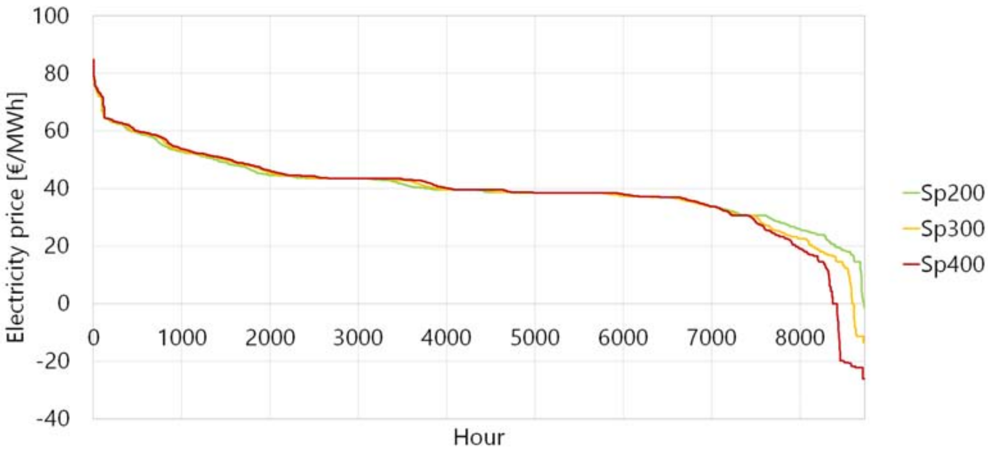


Figure 9.15: Price duration curve for the region DE-NW in 2030.

The most remarkable result is that the reduction of SP affect significantly the price duration curve only in the 2000 hours with the lowest price (right end of the graph).

In the rest of the hours, the effect is small and mainly concentrated around those hours where the curve is steeper and those positioned close to a fuel switch (e.g. from coal to gas).

This results can be explained by looking at the wind power duration curves. Specifically, the largest difference across scenarios is in those hours of very high wind speed, where the difference in the onshore in-feed is large and reaches almost 30 GW. Such a difference changes the magnitude of the shift in the supply curve, ultimately causing a different closing price in the market.
On the other hand, the difference of the power in-feed across scenario in the residual 6000 hours (with lower wind speeds) is not large enough to trigger a change in the marginal producing unit and cause a modification of the merit-order.
As already pointed out, the only exception is represented by those hours close to a higher price level, where the small difference in the wind power is enough to generate a change of the marginal unit setting the price.

In Figure 9.16, 9.17 and 9.18 it is possible to see the development of the last 2000 hours of the price duration curve from 2020 to 2030, for the region DE-NW in Germany. The more ahead in time, the more wind capacity is installed and the more scenarios differs between them in terms of characteristics of wind production, due to the large amount of new capacity installed. This is directly reflected in the price duration curves and in particular in the price during the most windy hours, where the merit-order effect is the strongest. A difference in the price in these hours is very relevant for wind producers since it is supposedly the time in which most of their power is produced. Therefore, any increase of the price is reflected in substantially larger revenues.

Another interesting thing to note is the lowest level reached by prices. In a large number of hours, for scenarios Sp300 and Sp400, the price is negative. This is due to different effects, among which municipal waste marginal cost, minimum limits for baseload production and subsidies to VRES. Municipal waste has a negative generation cost and base-load plants in the model are allocated a certain level of must-run generation. If the renewable production is too high, these plants reduce their bid in order to be dispatched and fulfill their minimum limit, potentially reaching negative marginal price. The factor that is mostly causing the negative prices is the subsidies assigned to the VRES in the model. Indeed, similarly to what happens in the real markets, this reduces their marginal costs and their willingness to accept compensation becomes negative.

If subsidies would not be present or if no subsidy would be payed to RES generators in case of negative prices, their marginal cost would be close to zero and so the prices in the market. In order to assess this possible future scenario, a sensitivity analysis regarding the subsidies to VRES is carried out in Chapter 10.

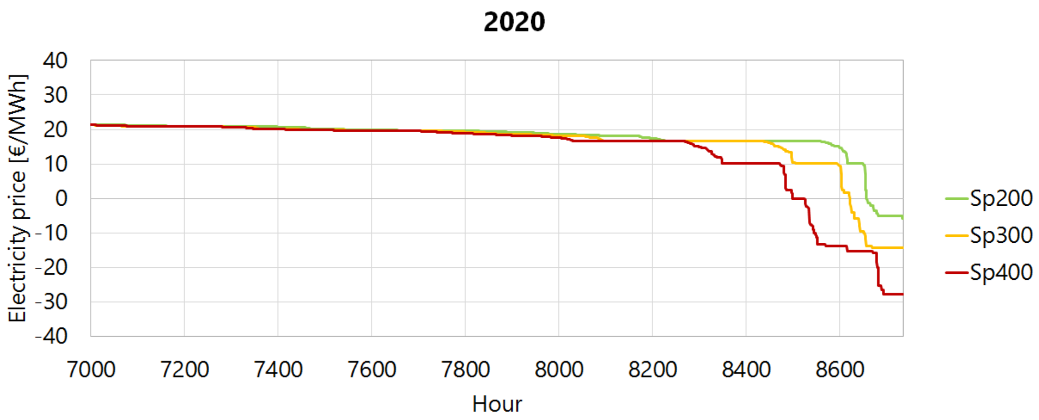


Figure 9.16: Last 2000 hours of the price duration curve in 2020 (DE-NW).

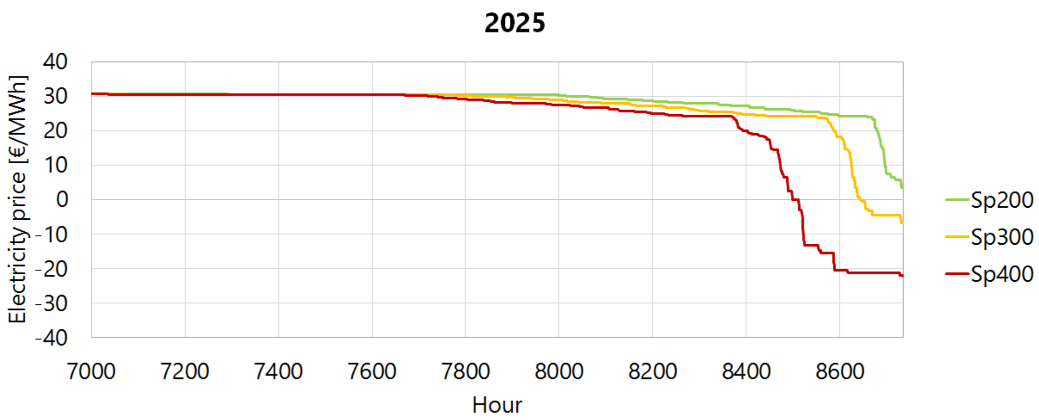


Figure 9.17: Last 2000 hours of the price duration curve in 2025 (DE-NW).

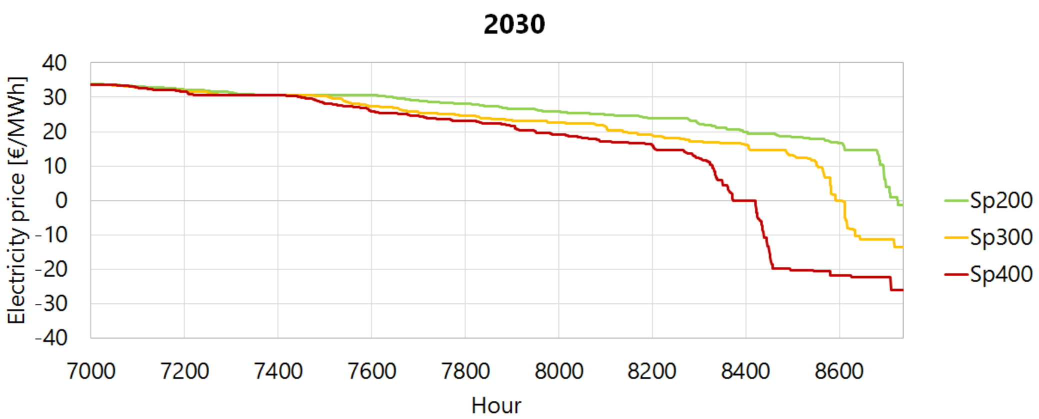


Figure 9.18: Last 2000 hours of the price duration curve in 2030 (DE-NW).

9.3 Total system cost results

One of the rationales for choosing lower specific power turbines is their system-friendly nature. It has been already shown how reduced specific power decrease the production from fossil fuels, make the residual load duration curve less steep and increase the capacity credit of wind.

In order to assess the system benefits in monetary terms, the total system costs were calculated for each scenario. The perspective is a socio-economic calculation of the costs for providing electricity and heat under the different technology scenarios simulated.

Total system cost is the sum of capital cost (CAPEX), maintenance cost (OPEX), fuel costs and emission cost for satisfying the demand of heat and power and is expressed in million euro (M€). While the first three figures are easier to define and calculate, the emission costs need to be specified. Indeed, it has to be defined what is the damage cost related to the emission of a ton of CO_2. In this analysis, the damage cost is set equal to the price of the CO_2, i.e. the ETS quota price. The cost of other emissions, such as SO_2 and NO_x, mainly related to coal power plants output, are not considered.
The following formula applies:

$$C_{tot} = C_{capex} + C_{opex} + C_{fuel} + E_{co2} * p_{co2} \tag{9.2}$$

Since all countries are connected and both imports and exports play an important role in the fulfillment of demand, it make sense to evaluate the system cost with a broad perspective, i.e. looking at the entire system and not at a single country.

Wind power cost No detailed cost figures for the different specific power turbines are publicly available from manufacturers, especially taking into account that some models are newly announced or did not see a large deployment yet. Moreover, as already mentioned, a certain SP could correspond to different combinations of generator size and blade length.
A top-up of 23% in the capital cost for "new models" compared to "old" ones is indicated in [101]. Additionally, [102] used a bottom-up turbine cost model and found a 13% increase in CAPEX from models featuring 200 W/m^2 to models with 325 W/m^2 at the same hub height.

Taking this into account, in the calculation of total system costs, it is assumed that the price for a specific power of 300 W/m^2 is 10% higher than for 400 W/m^2, while 200 W/m^2 models are 20% more expensive. Both variable and fixed O&M costs are assumed to be the same, following the analysis of [102].

Hydro power correction As already stated, the way hydropower dispatch is performed in the model introduces some differences in the total annual production. These differences in the total level of hydropower production are taken into account in the total system costs by adding a cost component related to the value of the amount of hydropower generation not used or used in eccess with respect to the central scenario (Sp300).

As a consequence, using more hydropower will result in higher costs, while using less will result in economic savings. This cost component could be divided between fuel cost related to the plants that have to supply the difference in the production, related emissions and O&M costs. Since this level of detail is not required, the cost entry related to hydropower is here labeled as *Other Costs*.

Resultant Total System costs

The total system costs, divided into the different components, are shown in Table 9.3.

Year	Scenario	Capital Cost	Fixed O&M	Fuel Cost	Variable O&M	Emission Cost	Other costs	Total costs
	Sp200	638,785	90,244	28,992	8,273	5,427	-136	**771,586**
2020	**Sp300**	640,460	90,479	28,929	8,274	5,419	-	**773,561**
	Sp400	640,719	90,795	28,980	8,272	5,418	-9	**774,174**
	Sp200	638,287	90,353	29,306	8,021	8,141	-73	**774,034**
2025	**Sp300**	640,592	90,803	29,309	8,014	8,109	-	**776,827**
	Sp400	641,788	91,451	29,407	8,018	8,108	19	**778,791**
	Sp200	637,065	91,960	24,335	7,726	7,717	104	**768,907**
2030	**Sp300**	642,369	92,727	24,501	7,740	7,774	-	**775,110**
	Sp400	645,033	93,773	24,782	7,747	7,830	46	**779,209**

Table 9.3: Total system costs and different cost components expressed in M€-2015 for the different SP scenarios.

Figure 9.19 shows the cost variations of Sp200 and Sp400 with respect to Sp300. As it is possible to note, the cost is decreased when lower specific power is deployed, while it is increased for higher SP. Most of the difference is related to a lower capital cost expenditure in the system, followed by fixed O&M and fuel cost. Emission costs and variable O&M changes are less sensible.
In the scenario Sp200, the cost is reduced by 6.2 billion € (0.8%) compared to Sp300 and 10.3 billion € (1.3%) compared to Sp400.

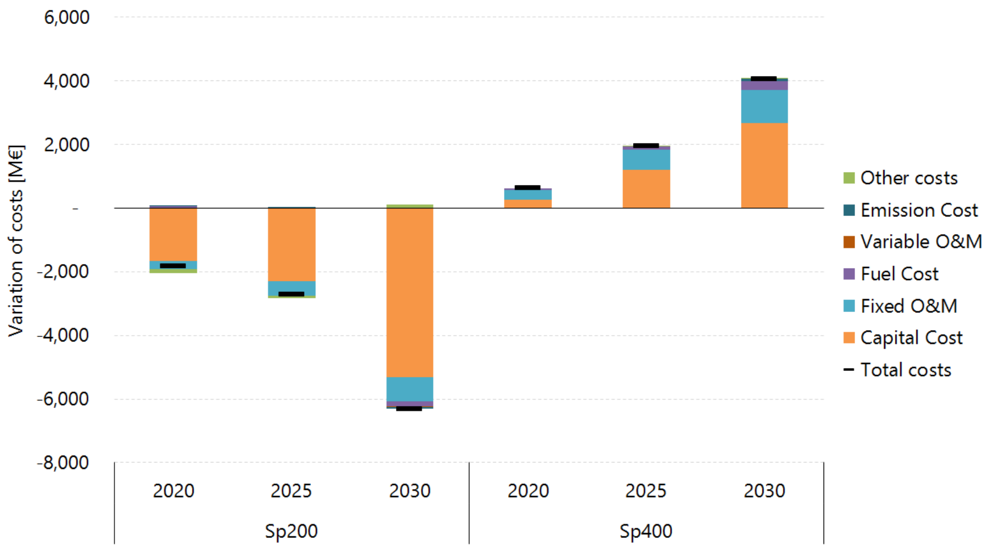


Figure 9.19: Variation in the system costs in different SP scenarios with respect to Sp300.

A large portion of the saving in capital costs is related to wind power (45% in

2030), since much lower onshore capacity is needed for the same penetration level. Nevertheless, not only total wind CAPEX is reduced, but also the total capital costs of fossil fuel plants. This is a direct consequence of the aforementioned reduction in the installed capacity of the entire system, due to the increase in capacity credit of onshore wind and the reduced need for backup power.
The effect is marked for peak power plants, namely natural gas and oil. To give an idea, capital cost expenditures for natural gas plants is reduced in 2030 by 3% in Sp200 compared to Sp300, for a total saving of 3,000 M€.
Figure 9.20 shows the difference of total CAPEX for new installations (excluding existing fleet) in the different scenarios. As clearly stands out from the graph, even though the specific investment cost per MW of advanced SP design is higher, the total CAPEX of new installations is lower, due to the reduced capacity installed in the system. It has to be kept in mind that this results refers to a capital cost top-up of 10% for Sp300 and 20% for Sp200 is considered, which in reality might be higher or lower.

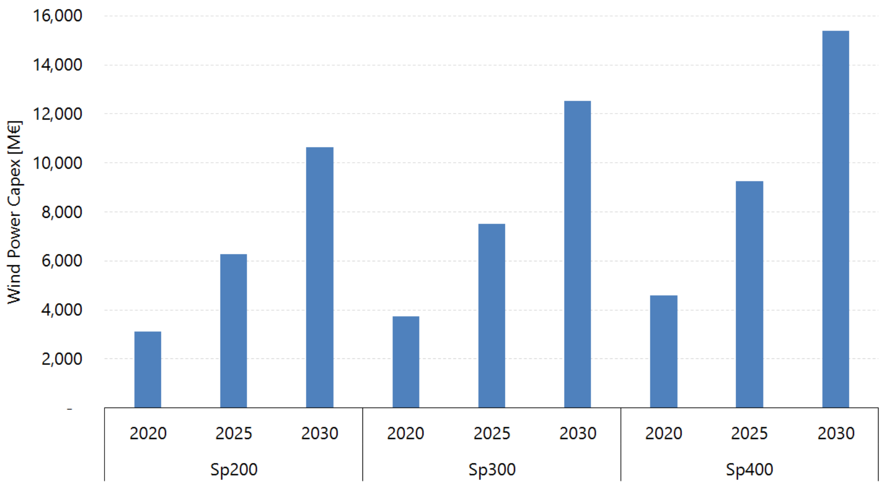


Figure 9.20: Total CAPEX for the entire system of new wind installations in different SP scenarios.

As for fixed maintenance costs, being dependent on the installed capacity, they follow the evolution of capital costs.

The development of fuel costs, and particularly the variations with respect to the central scenario, are directly derivable from the changes in the annual generation across scenarios shown in the *General system result* section (Figure 9.5).
On the one hand, higher fuel cost for Sp400 is due to a larger production of natural gas and a higher curtailment of wind, which generation is substituted by more expensive fuels. On the other hand, in Sp200, the fuel cost is slightly increased in the short term (2020), but largely decreased in 2030, thanks to the reduction of both natural gas and coal production in favour of more nuclear and lignite, characterized by lower fuel costs (baseload).

This large reduction in the total system costs is the main benefit of the deployment of low specific power turbines from a socio-economic perspective.

9.4 Value of wind results

Beside the decrease in total system costs, the other benefit from the deployment of lower specific power turbines is the expected increase of the market value of onshore wind.

As already presented in Section 3.3, Market Value of wind (MV) is the average revenue per energy unit produced by wind. The development of the annual average market value of wind for the three SP scenarios in Germany is shown in Figure 9.21, together with the average annual wholesale prices.
Beside the fact that Sp200 scenario shows a much larger Market Value than Sp400, it is interesting to note that over time the difference between average price and market value tend to increase. This confirms results from literature [4], i.e. that the Value Factor of wind is expected to drop in the next future, due to the increase amount of wind in the system, which pushes prices down in hours of high wind.

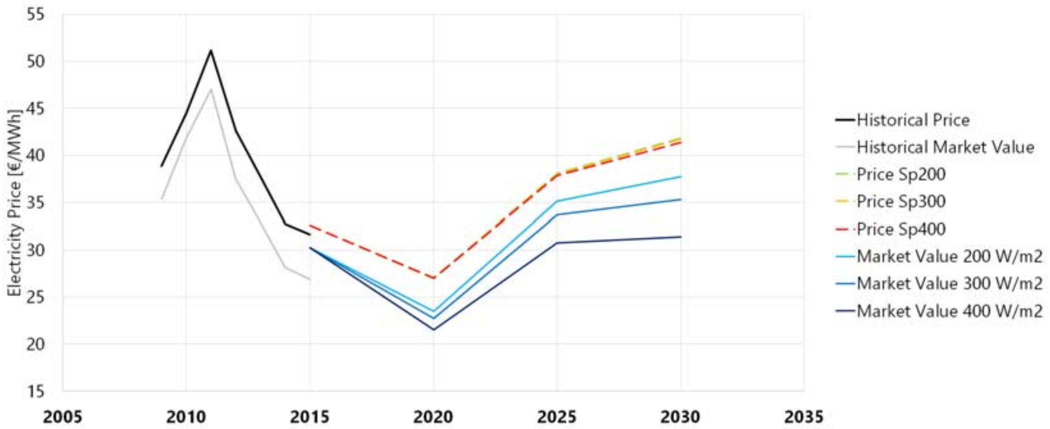


Figure 9.21: Development of Market Value with respect to price, historical and model results.

In the next sections the evolution of the Value Factor (VF) for different scenarios is assessed, focusing on various countries, regions and technology types.

Together with the VF for the different scenarios, the **Absolute value gap** (ΔV) between technologies is shown. It represents the absolute difference in the value factors of technologies and it will be shown mostly for Sp400 vs. Sp200 as extreme cases. Equation 9.3 shows how the absolute value gap is calculated.

$$\Delta V = \mid VF_{tech1} - VF_{tech2} \mid \tag{9.3}$$

Relative Value gap (Δv) is calculated by dividing the absolute value gap by the value factor of a technology.

Rationales for the value difference

Once a certain system in terms of capacity is given, two are the factors that concur to define the value of wind: price and wind production patterns.

As already shown in the previous sections, wind duration curves are different across scenarios, with more production at lower wind speeds for lower SP scenarios. Since the magnitude of the merit-order effect in the market depends from other parameters, among which the demand, there is no explicit correspondence between wholesale price and wind production in a certain hour.
However, it is possible to relate the wind production to different price levels. Figure 9.22 shows the cumulative wind production (right axis) correspondent to a certain level of market price (left axis). In order to do that, the hours in the year have been divided into 5 bins depending on the price level. For each bin, the cumulative wind production was computed and plotted for each SP scenario.

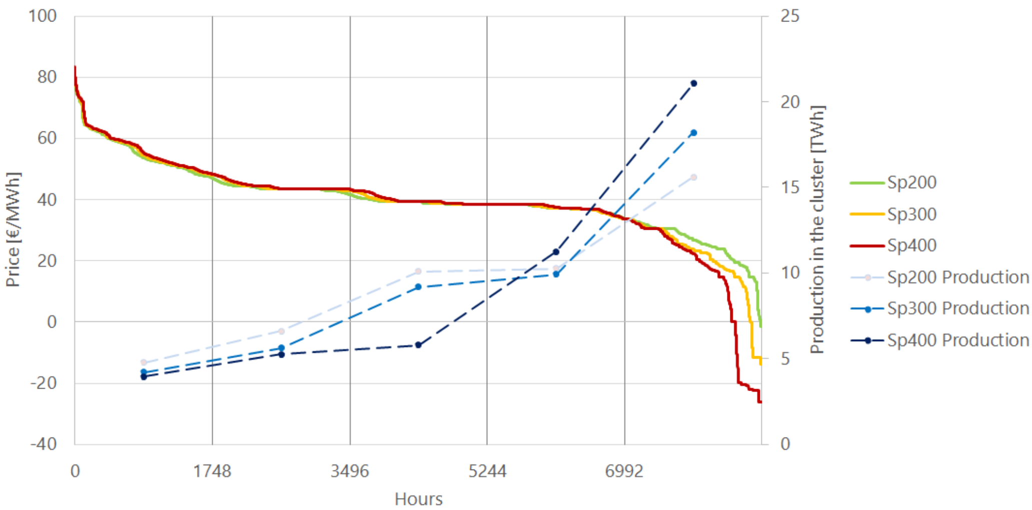


Figure 9.22: Cumulative wind production for 5 price level bins, DE-NW year 2030.

The result shows a trend that was expected: the generation of wind is lower at higher prices, while at lower prices wind produces much more. This graph condenses the two main reasons for a higher market value of lower specific power designs. Indeed, not only price on the low end shows significant increase in Sp200, but also the wind production in hours of higher prices is above the one from lower SP.
Another interesting fact in that in the central bin (C), the cumulative production shows a very large difference between Sp400 on the lower end and Sp300 and Sp200 on the higher one.

Value of Onshore wind - Germany

The resultant wind value factors for onshore wind in Germany for different years are shown in Figure 9.23, which constitutes one of the most important result of the study.

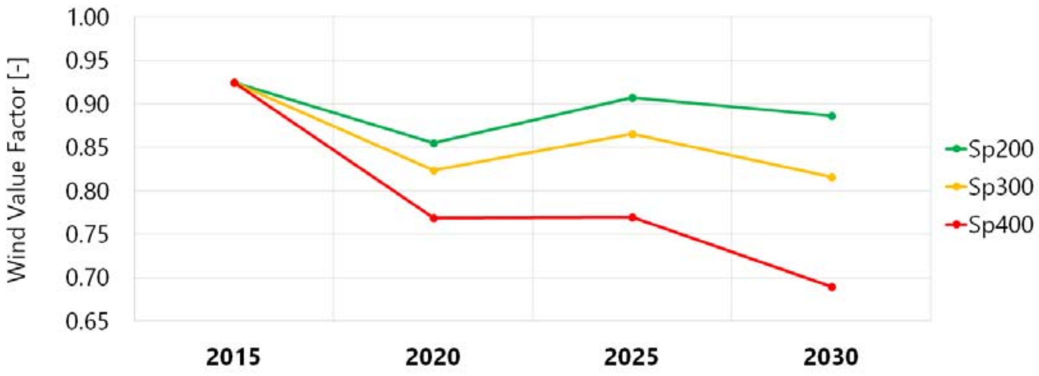


Figure 9.23: Development over time of VF of onshore wind for the three SP scenarios.

The first thing to underline is the resultant value factor (0.93) in 2015, the simulated historical year. While the graph shows only the onshore value and not the total wind value, which was 0.85 in Germany in 2015 based on realized data, a clear overestimation of the value factor emerges. This is analysed further and explained in the discussion (Chapter 11).

Another thing that can clearly be highlighted is that the value factor is not decreasing monotonically over time. Instead, in two of the three SP scenario, the VF is increasing between 2020 and 2025, while in Sp400 it stays constant.
The main reason is the incremented NTC in the North-South German corridor, which alleviates the congestion problems and enables wind power to be exported from the north of the country, where the resource is better and the installed capacity higher, to the south, where the consumption is much higher. A positive effect of increased interconnection on the value of wind has already been underlined by [60], which indicates a 28% higher value of onshore wind in 2030 when interconnection capacity is doubled, and by [11].

The use of turbines with a specific power of 400 W/m^2 cause a large drop in the VF, from 0.93 in 2015 to 0.69 in 2030. Instead, by utilizing a SP of 300 W/m^2, the value drop is limited and the VF in 2030 above 0.8, which is already an acceptable level, considering that the onshore wind penetration reaches 31% in 2030.
Low specific power turbines (200 W/m^2) performs much better than the previous ones when it comes to market value. Indeed, the VF in 2030 is as high as 0.88, underlining a large increment of the bulk market value compared to higher SP.

Figure 9.24 shows the absolute value gaps $\Delta V_{200-300}$ and $\Delta V_{200-400}$, which represents the difference in the value factors between scenarios. When looking at the magnitude of the absolute value gap for Sp400, it can be noted it is already quite

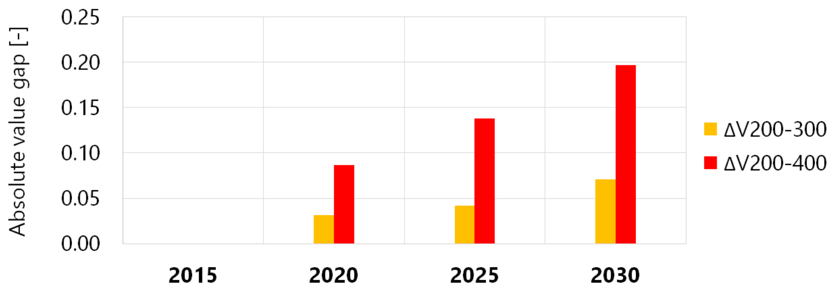


Figure 9.24: Magnitude of the absolute value gap for Sp200 compared to Sp300 and SP400 respectively.

high in 2020, with a value of 0.09 and it reaches a value of 0.20 in 2030. In relative terms this means that onshore wind is 29% more valuable when designing turbines with 200 W/m^2 of SP rather than 400 W/m^2.
Upgrading turbine design from 400 W/m^2 to 300 W/m^2 reduces this gap significantly already, with a absolute value gap which is reduced to more or less one third of the one for Sp400.

One thing to take into account is that the resultant Value Factors have to be intended in a socio-economic perspective. Indeed, as already mentioned, the market setup based on 4 market zones in Germany do not reflect the current situation in Germany. Nevertheless, the results highlight an important issue: at high penetration levels, the market revenues for wind producers could become much lower compared to dispatchable generators, potentially endangering the sustainability of wind investments.
Low specific power turbines could solve this problem by ensuring much higher revenues to producers. In our simulations, the value factors for Sp200 up to 2030 are around the value of 0.9, which is only slightly lower than the value simulated for 2015. With this design, the value drop in Germany would be somehow limited up to 2030, even with an onshore wind penetration equal to 31% of the total power demand in the country.

Onshore Wind Technology

Since historical wind fleet and new installations after 2016 are modelled separately, it is possible to assess the value factors for these two groups of onshore technologies. The resultant value factors and absolute gaps are shown in Figure 9.25 for the two extreme scenarios, namely Sp400 and Sp200.
The first thing to note is that not only the value of the new installations is increased significantly in Sp200 scenario, but also the value of the existing fleet sees a marked increment. It means that all wind producers could benefit from a reduction of SP in new installations, including the ones that are already in the system. This is due to the fact that the production of new turbines with a reduced SP is concentrated in different hours compared to the historical fleet, while if the new installations are achieved with high SP, they would produce in the same hours of the existing fleet.
The absolute value gap for historical turbines is increased by 0.07 in 2020 and 0.11 in 2030. In relative terms, the increase in the value in 2030 is 15%, from 0.76 to 0.87.

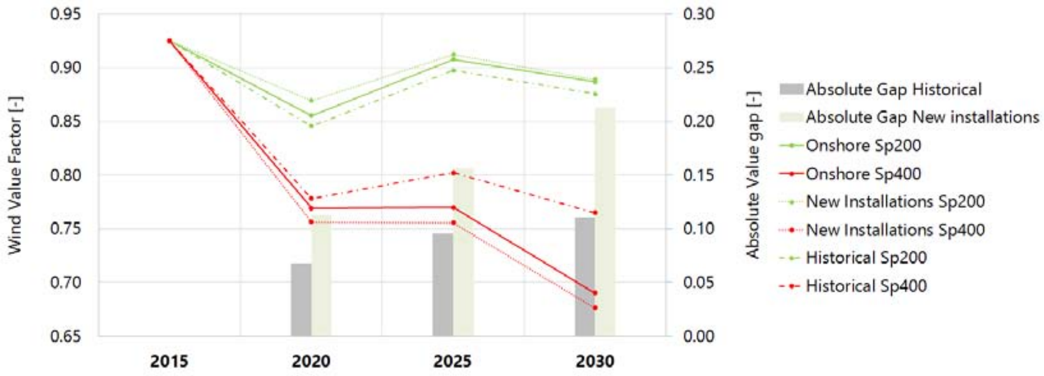


Figure 9.25: Development over time of VF of onshore wind: historical vs. new installations.

The value gap between technologies is the largest when looking at newly installed wind, and the gap is large already in 2020 (0.11) even though the majority of the fleet is still historical.

Value of Offshore Wind - Germany

The value of offshore wind is much higher and is reduced with a lower pace compared to onshore when increasing the wind penetration. Moreover, it is not largely affected by the choice of onshore wind technology, as displayed in Figure 9.26. However, there is a trend of increasing the value of offshore wind when lower SP is deployed for onshore, due to the reduction of *cannibalization* effects. One thing stands out in 2030: the value of offshore for Sp400 is more or less equal to the one for Sp200. This result is due to a very high curtailment of offshore wind in Germany in the scenario, which boosts the value of the wind dispatched.

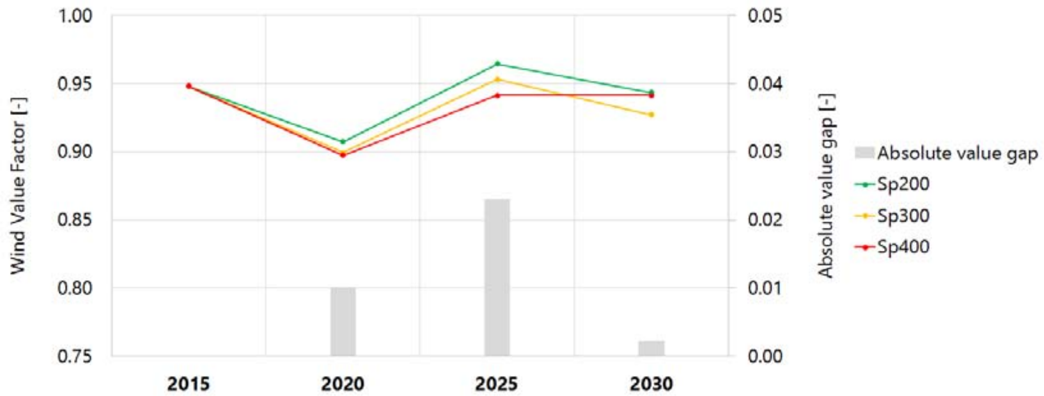
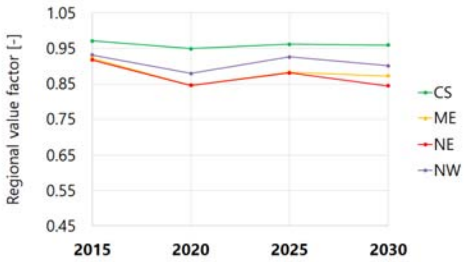


Figure 9.26: Development over time of VF of offshore wind for the three SP scenarios (left axis) and magnitude of the absolute value gap between Sp200 and Sp400 (right axis).

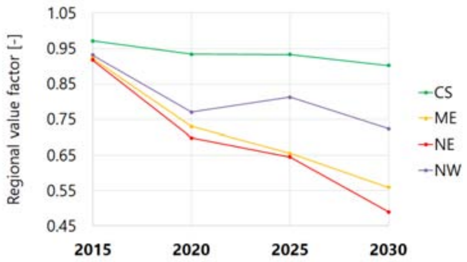
The resultant value factor for offshore wind confirms previous studies on the topic. A comprehensive assessment of the merit order effect in the period 2006-2014 revealed that the market value of offshore wind is in general higher compared with onshore wind [5]. In [12] a VF between 0.98 and 0.95 for offshore wind is projected in the period 2016-2020, confirming the trend of higher value factors for offshore wind. This increase is justified by a more uniform production profile with less pronounced generation spikes and higher full-load hours.

Regional value

Due to the subdivision of Germany in four price regions, it is possible to break down the value of onshore wind at a regional level. Figure 9.27 shows the development of the value factors for the four regions in Sp200 (a) and Sp400 (b).



(a) **Sp200**



(b) **Sp400**

Figure 9.27: Regional value factors for onshore wind in the 4 regions modelled in Germany and the two scenarios Sp200 (a) and Sp400 (b).

Value of wind in the region DE-CS, i.e. central/southern Germany, is much higher than in the rest of the regions and in both scenarios it is about 0.95. Some of the reasons behind this high value of wind are: higher power demand, lower wind share in the generation fleet and good interconnection to the southern regions, namely Switzerland and Austria.

The lowest values assessed are located in NE. This is quite surprising if considering that only 9% of new additions of onshore wind takes place in this region and throughout the years in all scenarios the onshore capacity is around 8-9% of the total. The value can be explained by the fact that the amount of dispatchable generation in the region is quite low and wind power constitutes the 60-70 % of all generating capacity.

As for the low value in DE-ME, it can be noted that the transmission capacity to DE-CS and its development is lower than the one from DE-NW to DE-CS. In addition, it can be noted that due to the marked increase in NTC between 2020 and 2025, the VF in DE-NW is increased in both SP scenarios, while for other regions the VFs increase only in Sp200 scenario.

Value of wind - Denmark

Finally, since wind power in Denmark has also been modelled quite in detail, the evolution of the VF in the country is assesed as a comparison to Germany.
Two main results stands out from Figure 9.28. First of all, the value factor is higher compared to Germany and secondly, the value gap across technologies is tighter.

The resultant VF for the three scenarios in 2030 are 0.93, 0.90 and 0.82 for Sp200, Sp300 and Sp400 respectively. This corresponds to an absolute value gap of 0.11 with Sp400 and 0.03 with Sp300.
Based on the results from the simulations performed, the benefit of going very low with SP in Denmark is somehow more limited compared to Germany.

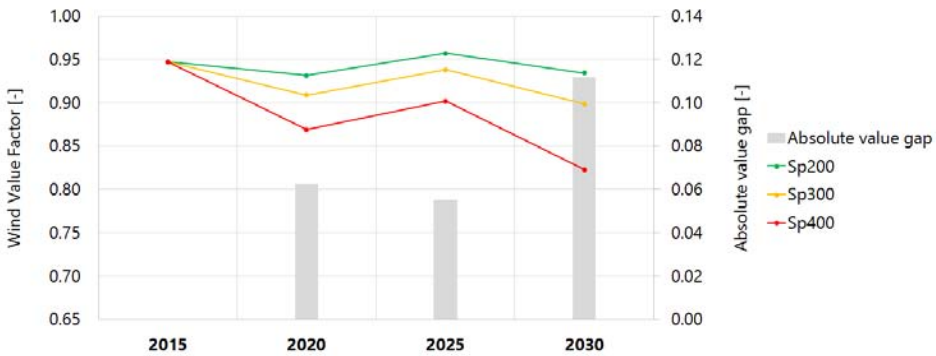


Figure 9.28: Development over time of onshore wind VF in Denmark for the three SP scenarios (left axis) and magnitude of the absolute value gap between Sp200 and Sp400 (right axis).

There are different reasons which can explain such differences. As already pointed out in the results from [38], flexible hydropower helps mitigating the value drop of wind power. Electricity produced from wind in Sweden was found 18% more valuable in Sweden than in Germany, at the same wind penetration level [38]. In our analysis, wind power in Denmark is between 5% and 19% (depending on the SP scenario) more valuable than in Germany in 2030, even with a mich higher wind penetration. In particular, the difference is more sensible in the Sp400 scenario (19%).
The main reason is that Denmark is very well interconnected to neighboring countries and especially Norway, with little or no bottlenecks limiting the import and export of electricity, therefore the pressure of wind power upon market is much lower.
Based on the results, it can be stated that Denmark integrates much better than Germany wind power if the technology features high SP, while in case of more system-friendly wind technologies (lower SP), this advantage is reduced.

As for the lower absolute gap between technologies, it has to be taken into account that Denmark reached a total onshore installed capacity of 3.8 GW at the end of 2015 [68], which is not far from the total onshore potential. As a consequence, even though new turbines are substituting decommissioned plants, the share of new installations on the total fleet is not as high as in Germany, where large development each year is expected.

9.5 Hub Height Scenarios - hh90, hh120, hh150

In general terms, the effect of increasing hub height from 90m to 150m has a lower impact compared to the decrease of specific power from 400 to 200 W/m^2. Specifically, this can be seen in the changes of wind and price duration curves, system impacts, as well as on total system costs and value of wind.
Therefore, a brief results overview for the hub height scenario is presented in this section, following the same structure of the SP ones. Other results and graphs for the three SP scenarios are shown in Appendix C.

Variations in the annual power generation The increased height of the rotors enables to produce more energy from baseload plants compared to peak production. Reducing hub heights, instead, increases the production of fossil fuels from natural gas and coal, and to a lower extent biomass, while reduces baseload production of nuclear and lignite. It has to be noted that large variations of hydropower are present in the scenarios, making them more difficult to compare. The results are showed in Figure C.1.

Wind Installed capacity and CF The difference across HH scenarios of the new wind capacity needed to reach the exogenous wind generation target, is lower compared to SP ones. Increasing the hub height from 90 m to 150 m shows a reduction of capacity of roughly 17% in all the simulated years. In 2030 this corresponds to almost 10 GW of difference in the total capacity.

The average capacity factors in Germany in the three HH scenarios are 0.28 for hh90, 0.31 for hh120 and 0.34 for hh150. A visualization of the resultant FLH (and equivalent CF) is shown in Figure C.2.

			2015	**2020**	**2025**	**2030**
		150m	0	14.1	31.4	46.2
New wind capacity	[GW]	**120m**	0	15.3	34.0	50.1
		90m	0	17.0	37.9	55.9

Table 9.4: Wind Power capacity in Germany: evolution of new installations for different HH scenarios, at the same wind penetration level.

Wind power duration curves The resultant wind duration curves at different hub height levels are shown in Figure C.3 for the year 2030. As a result of the increased productivity in terms of annual FLH and the consequent reduction of capacity, the duration curve at increased hub heights is smother for the hh90 scenario. It is interesting to assess the difference between the wind duration curve of advanced HH scenario hh150 and the advanced SP scenario Sp200. As can be seen, the effect on the wind power duration curve of increasing hub height by 30 m is much smaller than reducing the specific power by 100 W/m^2 (Figure 9.29).

Residual load curve and Capacity credit The residual load duration curve shows similar effects compared to the SP scenarios, but a smaller reduction in re-

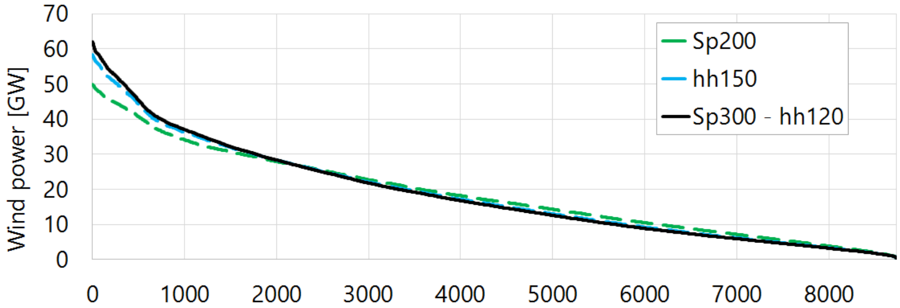


Figure 9.29: Effect of increasing HH or reducing SP from reference scenario Sp300 - hh120 to advanced scenarios, year 2030.

newable surplus. The amount of hours with a negative net load are down by 17%. The capacity credit increases with the height of the towers and in 2030 it is 3% higher for hh150 than for hh90. Both graphs for residual load and capacity credit can be found in Appendix C.

Wind Curtailment The higher the hub height is, the lower the wind curtailment. Figure 9.30 shows the resultant curtailed wind energy in Germany.

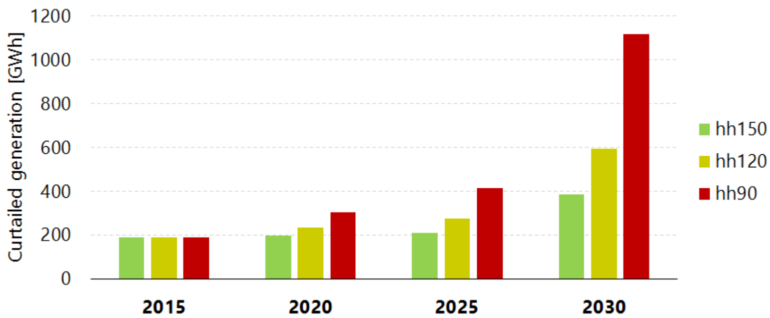


Figure 9.30: Annual curtailment of wind power in Germany in different HH scenarios.

Total system costs The same definition of total system costs given in Section 9.3 is here used and the same considerations regarding hydropower holds. As for wind turbine costs, it is here assumed that increasing hub heights from 90 to 120 m results in a cost top-up of 17%, while going from 90 to 150 m causes the specific power to grow by 25%. These assumptions are based on cost figures of a recent market analysis for Germany [103].

The results across scenarios are here shown in Figure 9.31. With the assumptions of specific investment cost mentioned, the total system costs are more or less constant across HH scenarios. Only a small reduction in costs (0.1%) in 2030 is resulting in hh150 compared to hh120. On the other hand, quite surprisingly, hh90 is also performing better than hh120 in terms of system costs. As can be seen in Figure C.7, hh120 shows the maximum total CAPEX across scenarios, meaning that the reduction of capacity compared to hh90 is outweighed by the additional specific installation cost. Even if costs related to wind power are not considered, there is no consistent system cost benefit when increasing hub height. The detailed cost results are presented in Table C.1 in Appendix.

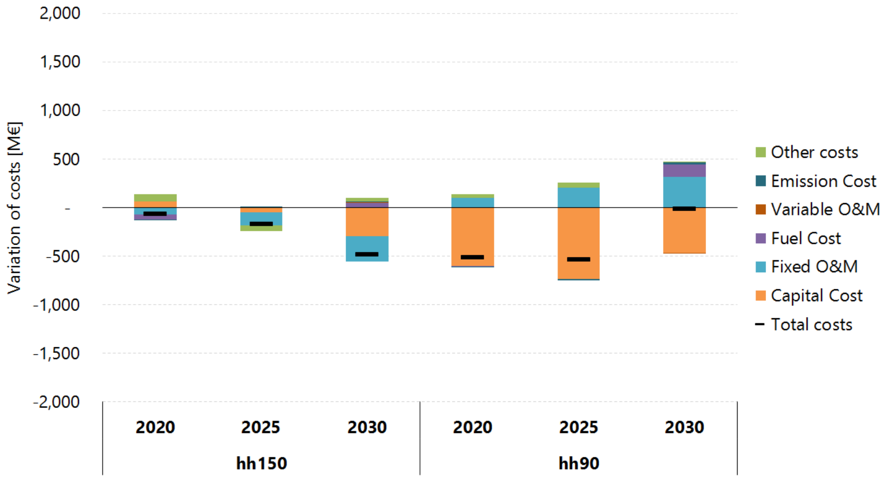


Figure 9.31: Variation in the system costs in different HH scenarios with respect to hh120.

Value of wind The resultant value of wind for onshore wind in Germany is shown in Figure 9.32. As it is possible to note, the spread of value across HH scenarios is much lower compared to SP results. The absolute gap between (ΔV_{150-90}) reaches a value of 0.07 in 2030 compared to the 0.20 of the two extreme SP scenarios (Sp400 minus Sp200). In relative terms, deploying turbines with hub heights of 150 instead of 90 meters in Germany increase the value factor by roughly 10%.

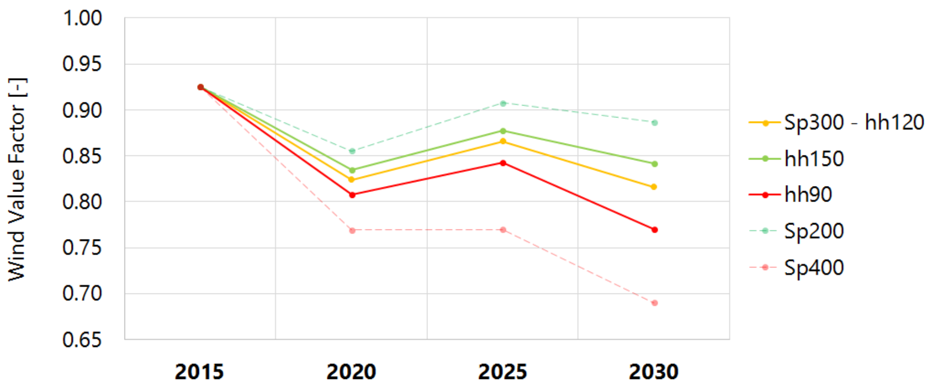


Figure 9.32: Development over time of VF of onshore wind for the three HH scenarios, compared to the SP ones.

In Denmark, the absolute value gap in the HH scenarios is even lower, reaching the value of 0.03 in 2030. This corresponds to a relative increase in the value of around 3% when switching from a hub height of 90 meters to a hub height of 150 meters.

10

Sensitivity analysis

10.1 Sensitivities setup

In order to assess the robustness of the main results with respect to input parameters, sensitivity analyses are performed. Due to the large amount of model runs, i.e. 5 wind technologies and 3 modelled years, the focus of the sensitivity will be year 2030 and specific power scenarios.
In particular, the effect of some of the main parameter assumptions on both the value of wind and the absolute delta between SP technologies will be tested.

The selected parameters are the following:

- Subsidy level
  - No subsidy for VRES at negative prices
- Fuel prices
  - High and low coal price
  - High and low gas price
- CO_2 price
  - CO_2 price collapse
  - Doubled CO_2 price

The choice of parameters to be assessed is justified by the expected magnitude of their influence on the results and the level of uncertainty related to their development.
The subsidy level and the fact that VRES has a negative marginal cost whenever they are incentivised is causing a large amount of hours with negative wholesale electricity prices. This largely affect the value of wind, since in those hours wind has a high production.
As underlined in [4], fuel and CO_2 price development are affecting the absolute and relative value of VRES through three channels: changes of the electricity price level, changes of the slope of the merit-order curve via variable cost changes, and changes of the merit-order curve via changes in the capacity mix. Moreover, fuel and CO_2

prices are mentioned by [104] as two of the main driving factors for the level of the merit-order effect. Indeed, they affect the supply curve by increasing or decreasing its steepness, which is the most important parameter that determines the merit-order effect volume [104]. Moreover, a change in these prices can drive a different optimal configuration of the system by making some generators more competitive than the base case.

For this reason, sensitivities on fuel and CO_2 prices is constituted by both an investment run and a dispatch run. It has to be underlined that investments are optimized not only in 2030 but progressively in 2020, 2025 and 2030 and prices are changed in all years up to the year simulated, so that the system takes into account a consistent pathway.

Differently, for the sensitivity on the subsidy level only a dispatch optimization is performed, implicitly assuming the same penetration level would be achieved with a different subsidy scheme, which does not affect dispatch decisions.

The selected sensitivities are simulated both for Sp200 and Sp400 in order to assess the value gap, and correspond to a total of 27 model runs.

10.2 Subsidy level - negative prices

The idea behind this sensitivity analysis is assessing the impact on the value of wind if subsidy schemes on solar and wind power wold not affect dispatch decisions.
As seen in the price duration curves, there was a large number of hours with negative prices, many of which were due to wind and solar setting the price at their marginal cost, which in case of incentives is equal to variable O&M cost minus the subsidy level.

In different countries, such as Denmark and Germany, the idea of giving subsidy at negative prices is being heavily questioned.
In facts, Denmark still provides incentives to onshore plants at negative prices, while in the offshore tenders it is specified that no incentive is paid at negative prices [105]. Germany has adopted a different strategy with EEG14 (§24) [28]: the so-called *6-hours rule*. Under this regulation, if the price is negative for 6 or more consecutive hours, RES producers gets no subsidy and bares the negative price only.

The "Guidelines on State aid for environmental protection and energy 2014–20" [106], call for more market-based support mechanisms and specifically specifies that "*measures have to be taken to avoid renewable generators producing electricity under negative prices*". In this perspective of making renewables participating more and more to the market enhancing competition, it is foreseeable that in the future market and policy setup no subsidy will be paid at negative prices.

In the context of dispatch simulation like the one performed, since VRES installed capacity is exogenous and not affected by subsidies and those energy sources are price-makers only in the negative part of the supply curve, setting the subsidy equal to zero is equivalent to cancel the payment of the support at negative prices. Therefore, it is representative for the situation discussed above.

Figure 10.1 shows the resulting duration curves for the three SP scenarios without incentive at negative prices.

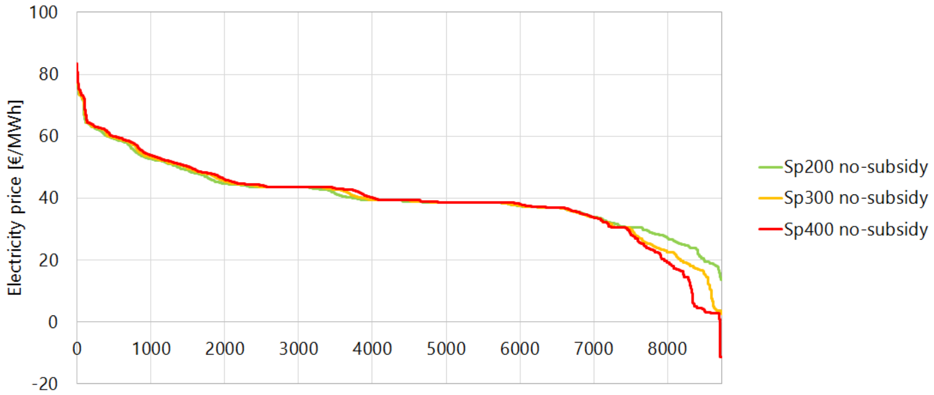


Figure 10.1: Price duration curves for DE-NW for the three SP scenarios with no incentives for solar and wind.

The amount of hours at negative prices is drastically reduced, since solar and wind do not have a negative marginal cost anymore. In Sp400, there are still few hours with negative prices, mainly driven by the must-run nature of municipal solid waste.

The effect on both value of onshore wind in Germany, as well as on the absolute gap are shown in Table 10.1.

		Sp200	**Sp300**	**Sp400**
Subsidy	Value factor	0.89	0.82	0.69
	Absolute gap		0.20	
No Subsidy	Value factor	0.89	0.83	0.74
	Absolute gap		0.15	

Table 10.1: Variations of onshore value factor for the three scenarios and absolute gap with and without subsidies for solar and wind.

As expected, the largest increase in the value factor is for Sp400, which increases by 0.05 absolute points. Indeed, it was the scenarios with the largest amount of hours with negative prices.
The large increase in prices at the right end of the price duration curve compared to a situation where incentives are considered (see Figure 9.15) affects a lot the value of wind since those hours are the ones with the largest wind production.
It can be expected that this change in the value factor of higher SP is less marked in years 2020 and 2025, since the hours with negative prices are fewer.

The absolute gap between Sp400 and Sp200 goes from 0.20 to 0.15, driven by the increased VF of higher SP.

It has to be taken into account that, since having no incentives increment the marginal cost of solar and wind, they could be pushed out of the dispatched generation in case the price goes down to very low levels and therefore curtailment of these two sources is affected as well.
When there is no incentive at negative price, curtailment of wind is increased by 495 GWh (+18%) in Sp400, 356 GWh (+60%) in Sp300 and 295 GWh (+86%) in Sp200. Additionally, curtailment of solar in Sp400 increases by 15 %.

10.3 Fuel prices

In order to assess the separate contribution of gas and coal prices, the price changes were simulated individually, meaning that when high coal prices are assessed, the gas price is kept constant, and so for the rest of the sensitivities. This approach is different from simulating a consistent set of prices, e.g. based on a different WEO scenario (*Current Policies, New Policies, 450 ppm*). It could be argued that fuel prices are linked and they are substitutes goods, so that a change in the price of one fuel would cause a variation in the others. Nonetheless, in this analysis the specific effect of the single fuel prices in the market value of wind and the absolute value gap is assessed.

The price reference of the base set of scenarios is the *450ppm* scenario of WEO15 [77]. In the sensitivity, the high price level for both fuels is chosen according to *Current Policies* of WEO15, while the low price level is chosen so that the reduction of price has the same magnitude of the increase in the high case. The resultant prices are shown in Figure 10.2 and Table 10.2.

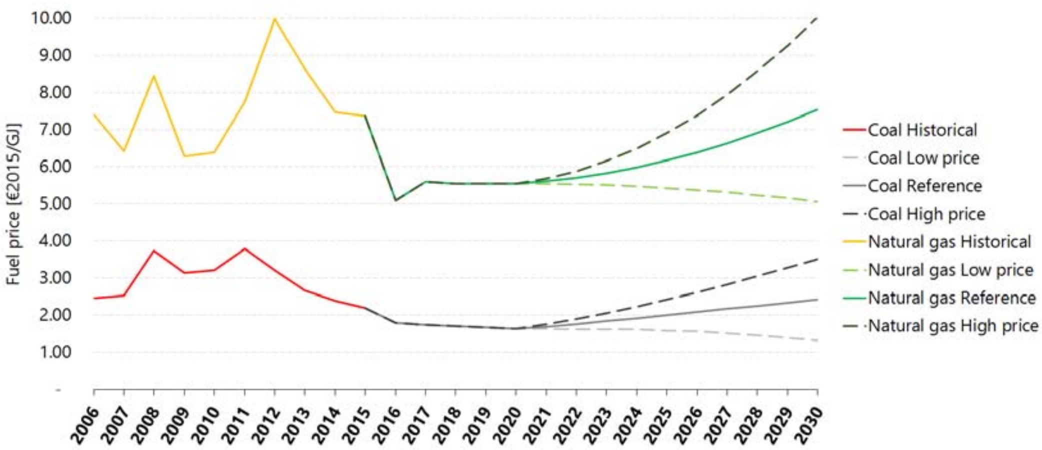


Figure 10.2: Visualization of fuel price sensitivities levels.

Coal prices

Results for the coal price sensitivity are presented here. Both the difference in the investments due to high/low coal price and effect on price duration curves and value of wind are assessed.

		Low	Base	High
Coal	Price [€/GJ]	1,3	2,4	3,5
	Variation [%]	-45%	-	45%
Gas	Price [€/GJ]	4,7	7,2	9,7
	Variation [%]	-35%	-	35%

Table 10.2: Fuel price change in the sensitivity scenarios.

Effect on the investments As showed in Figure 10.3, an increase in coal prices of 45% (correspondent to *Current Policy* scneario of WEO), reduces the coal capacity across all the modelled region by 20 GW in Sp400 and 22 GW in Sp200 if compared to the base scenarios. Lignite and Fuel oil capacities are decreased as well. On the other hand, gas capacity is increased by roughly 24 GW in both SP scenarios, in order to substitute the decommissioned coal.
If the price of coal decreases by 45% with respect to the base scenarios, the effect on the installed capacity is much less sensible. Indeed, many countries have restrictions on coal investments. The small increase in natural gas in the low coal price scenario is related to these regulations: in countries where limitations to coal investments are present (such as Germany, Denmark and UK), some coal plants are decommissioned because not competitive and the natural gas replace those.

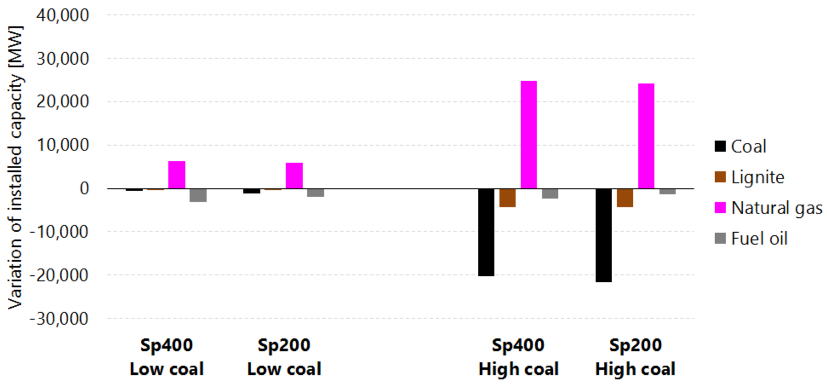


Figure 10.3: Variations of fossil fuel installed capacity driven by higher/lower coal price, compared to respective Base scenarios.

It has to be pointed out that when considering only Germany, the reduction of coal capacity is not balanced by increased gas investment, but most probably covered by additional imports.

Effect on prices and wind value The resultant hourly dispatch is affected both by the different system configuration and by the fuel price itself. Figure 10.4 show the effect on the price duration curve for DE-NW of higher prices (black) and lower prices (blue) with respect to the base case (yellow). Both Sp400 (solid lines) and Sp200 (dotted lines) are displayed.

In general terms, it can be noted that the most pronounced effect is in the central part of the price duration curve, where coal is price setting. Moreover, lower coal prices tend to increase the steepness on the left part of the graph (hours 1000-3000). The reason for the increased steepness is the larger difference across marginal prices of gas and coal.
One thing to note is that an increase in the slope of price duration curve during high price hours increases the volume of the merit-order effect in Sp200. The mechanism is the following. A lower coal price reduces the marginal cost of coal plants resulting in a steeper supply curve, due to a larger difference to gas marginal price. As a consequence of the steepness, even the small increase of wind generation at higher prices is shifting the supply curve to right and drive a price reduction. This slightly reduces the value of Sp200.

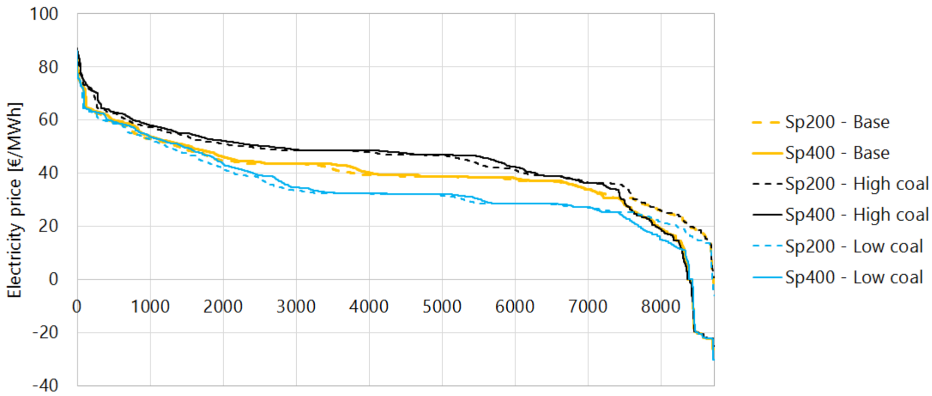


Figure 10.4: Change in the price duration curve of DE-NW with higher/lower coal prices, for scenarios Sp400 (solid) and Sp200 (dotted). Lower prices are shown in blue and higher prices in black.

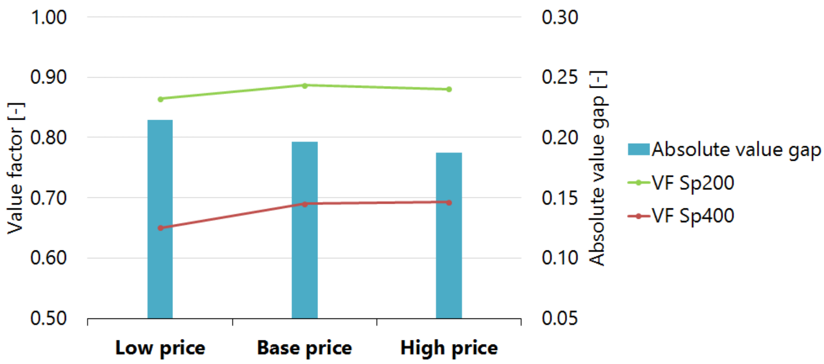


Figure 10.5: Change of VFs (left axis) and absolute value gap (right axis) for different coal prices.

The effect on the value of wind and the value gap is shown in Figure 10.5. In general terms, value factors are not largely affected by the change in coal price. However, there is a tendency towards higher value factors as the coal price increases. At the same time, it can be noted that the absolute gap is slightly decreasing, therefore

Sp400 is getting comparatively more valuable than Sp200.

Gas prices

Effect on the investments System results for gas sensitivity are displayed in Figure 10.6. Low gas price causes higher investment in gas and larger decommissioning of coal, lignite and oil compared to the base scenarios. Natural gas plants tend to become somehow a substitute for coal ones.
High gas price affects the system to a lower extent, due to the aforementioned limitations in coal investments, little more coal is installed compared to base and lower natural gas capacity.

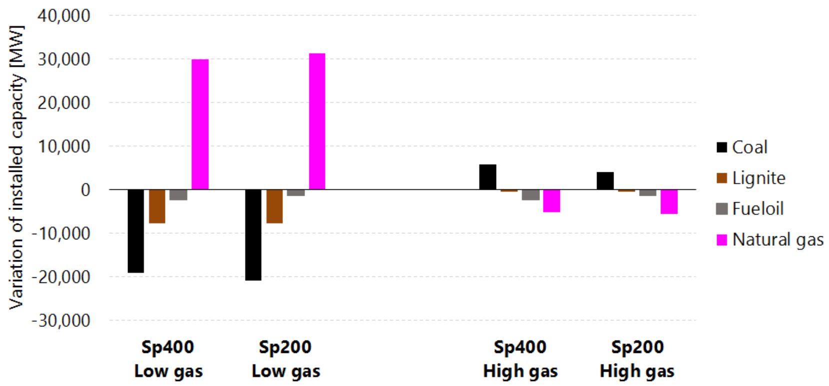


Figure 10.6: Variations of fossil fuel installed capacity driven by higher/lower gas price, compared to respective base scenarios.

Effect on prices and wind value As can be seen in Figure 10.7, the major effect on the duration curve is a price increase in the 2000-3000 hours with the higher price, i.e. when gas is setting the price.

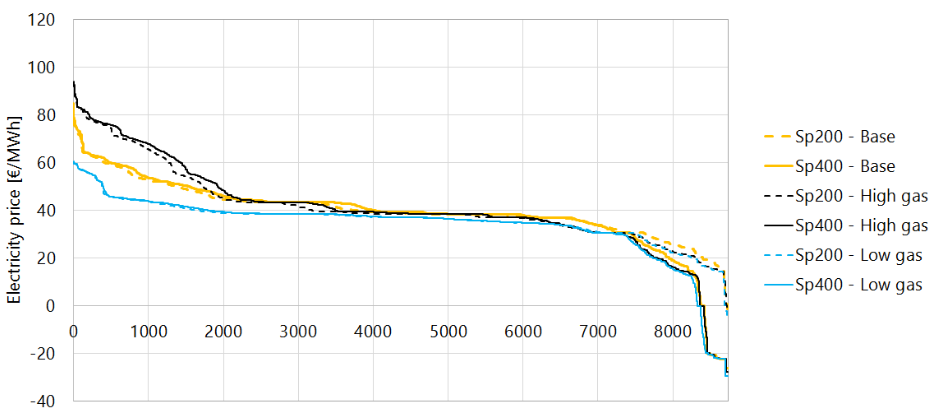


Figure 10.7: Change in the price duration curve of DE-NW with higher/lower gas prices, for scenarios Sp400 (solid) and Sp200 (dotted). Lower prices are shown in blue and higher prices in black.

Increasing gas price cause the curve to become steeper in correspondence to gas marginal cost, while a lower fuel cost tend to flatten it. This is due both to a higher difference with coal price and to the effect of the different efficiency of gas plants, which is more marked with a higher fuel price. Similarly to what described for coal, this causes a more marked merit-order effect in the market, reducing the price of Sp200.
This effect ultimately leads to a reduction of the benefit of lower specific power, since the price they see at low wind production is lower compared to higher SP.

The effect on the VF and the absolute gap is shown in Figure 10.8. Value factor for both Sp200 and Sp400 slightly decreases with higher gas prices. This is related to the fact that a higher gas price affects average electricity prices more than market value, since wind power does not have a large production during those hours. Since the value for Sp200 is reduced more compared to Sp400, the absolute value gap decreases with higher gas prices similarly to the case of coal sensitivity.

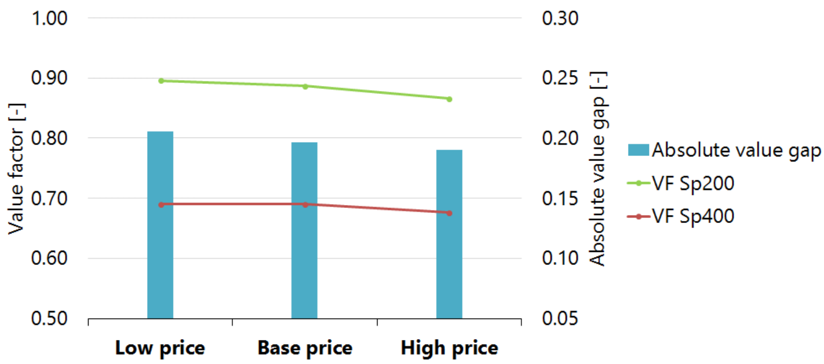


Figure 10.8: Relative change of VFs (left axis) and absolute value gap (right axis) for different gas prices.

10.4 CO2 price

In order to assess the effect of carbon prices on the results, two sensitivity scenarios are performed: a price collapse scenario and a scenario with doubled CO_2 price.
The price collapse scenario is meant to represent a failure of the emission trading schemes (ETS) to regain their role as an effective financial incentive of emission abatement and assumes that current low prices for EU Emission allowances (EUA) and for EUA future contracts are holding until 2030 [76].
On the other hand, scenario with high CO_2 prices assumes a double carbon price in the market, reaching a value of 30 €/ton in 2030.
Figure 10.9 shows the CO_2 price development for base scenarios and the two sensitivities.
Another aspect to be taken into account is that there are some cross-related effects that are not taken into account in this sensitivity analysis. As an example, CO_2 quota prices and subsidy schemes are somehow linked. A higher CO_2 price, i.e. emissions internalized in the fossil fuel power cost, would indirectly result in higher revenues for RES and correspond to a indirect incentive to RES source. As a con-

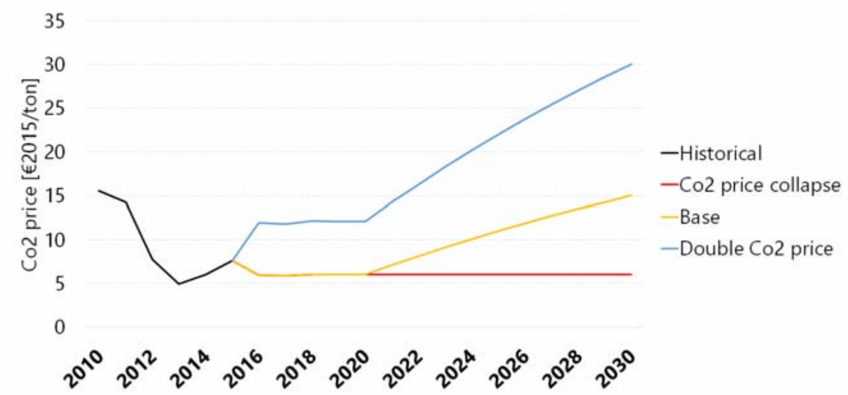


Figure 10.9: Visualization of CO_2 price sensitivities levels.

sequence, these sources would require a lower subsidy to be feasible and this could potentially change the negative price zone of price duration curves, thus the VF. While it is important to mention these effect, they are not dealt with in the sensitivity analysis, which by nature is not meant to reflect these concatenated effects.

CO2 sensitivity results

The effects of carbon pricing in the fossil fuel investments and decommissioning in the entire system is shown in Figure 10.10. As expected, higher CO_2 prices increase natural gas and decrease coal and lignite, while with lower prices slightly more coal and less gas are present in the system.

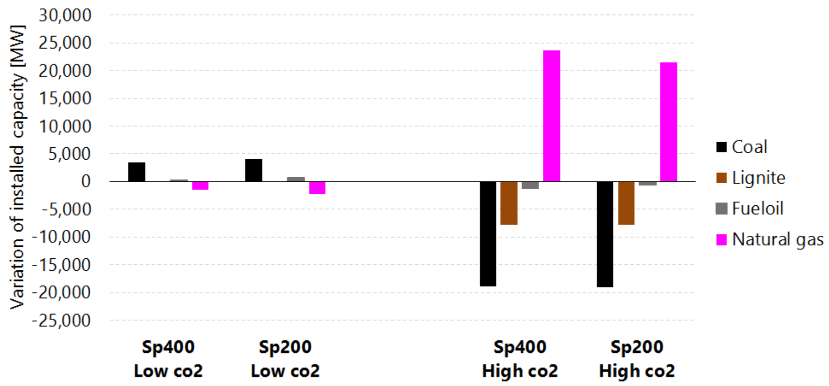


Figure 10.10: Variations of fossil fuel installed capacity driven by higher/lower CO_2 price, compared to respective base scenarios.

As for price duration curve and value factors the results are displayed in Figure 10.11 and Figure 10.12 respectively.
Higher carbon prices makes the curve more flat, while lower carbon prices tend to make it steeper. Indeed, having coal larger CO_2 emissions, its marginal costs is affected more by the change in quota prices.

As for the value factors, it can be seen that for both scenarios there is an increase

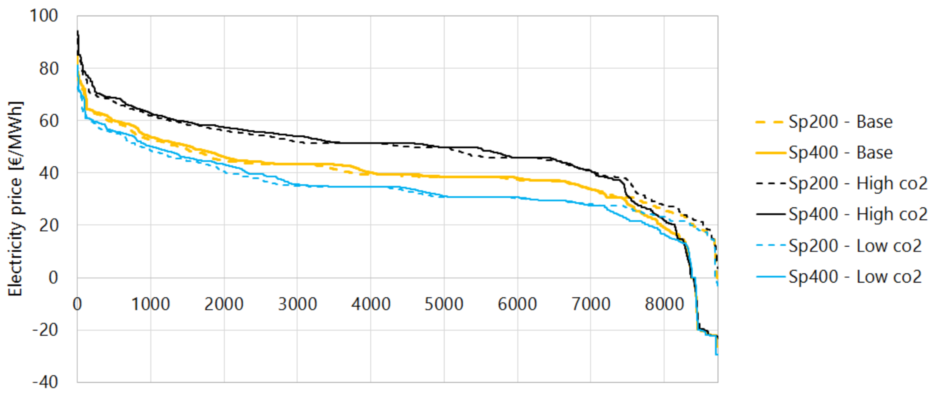


Figure 10.11: Change in the price duration curve of DE-NW with higher/lower CO_2 prices, for scenarios Sp400 (solid) and Sp200 (dotted).

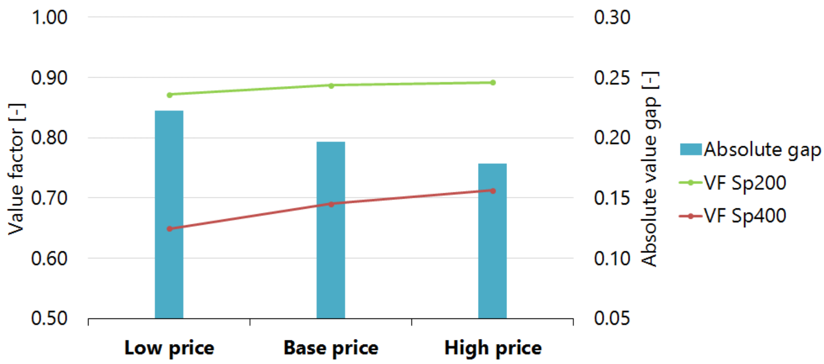


Figure 10.12: Relative change of VFs (left axis) and absolute value gap (right axis) for different CO_2 prices.

of VF as a result of a higher CO_2 price. The change in the value is more marked for Sp400 compared to Sp200, thus making the value gap slightly smaller.

10.5 Sensitivity recap

The effect of fuel and carbon prices, as well as the impact of VRES incentives to dispatch, have been assessed.
The results confirmed a marked benefit in the market value of onshore wind (and respective value factors) when deploying lower specific power turbines.
The onshore absolute value gap between the two scenarios Sp200 and Sp400 is in the range 0.18-0.23 for all fuel and CO_2 sensitivities.
The largest difference is related to the subsidy level and to the way it influences dispatch. The advantage of lower specific power in terms of onshore value factors is reduced by 25% (absolute gap from 0.20 to 0.15) when VRES do not receive a subsidy or they are not allowed to bid at negative prices.

Table 10.3 recaps results from the different sensitivity analyses, in terms of value factors for the two scenarios Sp200 and Sp400 and the absolute value gap between the two technologies.

	Sp200 Value factor	**Sp400 Value Factor**	**Absolute gap Sp200-Sp400**	**Relative value gap Sp200-Sp400**
Base	0.89	0.69	**0.20**	29%
No subsidy	0.89	0.74	**0.15**	25%
Low coal	0.86	0.65	**0.21**	32%
High coal	0.88	0.69	**0.19**	28%
Low gas	0.90	0.67	**0.23**	34%
High gas	0.87	0.68	**0.19**	28%
Low CO2	0.87	0.65	**0.22**	34%
High CO2	0.89	0.71	**0.18**	25%

Table 10.3: Recap of sensitivity analysis: onshore VF for Sp200 and Sp400, absolute value gap and relative value gap (year 2030).
(mismatch in calculations are due to decimals)

Beside the robustness of market value increase, some interesting insight on the relation between value of wind and fuel prices were highlighted. Higher coal prices tent to increase value factors due to more flat curve. On the other hand, the increase in gas price reduces VFs, since the curve is getting steeper and average price is increasing more than market value of wind.
For CO_2 prices the effect is similar to coal. Higher carbon prices make the curve less steep and thus increase the value factors.

As a further confirmation, Figure 10.13 shows the development of wholesale prices and market values. Figure 10.13(a) is suggesting that the price of coal is driving both the average wholesale electricity price and the market value of wind. This is a confirmation of what was reported in a recent price projection study from *Dansk Energi* [34].

As for gas, average price and market value shows saturation in correspondence to high prices. However, the relative increase of MV with higher gas prices is lower than for electricity prices, reducing the value factors.

(a) Coal price (b) Gas price

Figure 10.13: Change in wholesale electricity price and MV for difference levels of coal and gas prices.

When looking at the gap between Sp200 and Sp400, it is reduced with the increase of coal, gas and CO_2 prices.
One of the reasons for this development is related to the merit-order effect at lower wind speeds. As already shown throughout Chapter 9, not only lower specific power turbines produces more at lower wind speeds, but also a larger production in hours of high prices was demonstrated. The more steep the supply curves get following a fuel price change, the more likely it is that the increased output of lower SP (Sp200) during higher price hours drives merit-order effect and thus reduces prices.
As a consequence, the comparative benefit of higher fuel prices in Sp200 is limited by a price reduction driven by the different wind production pattern of the two technologies.
In addition, since value factors of Sp400 are much lower than the ones for Sp400, they are more sensitive to fuel price change.

To conclude, this sensitivity analysis was meant to assess the robustness of value gap across different price scenarios, therefore the long-term effects of fuel price changes are assessed by means of both investments and dispatch.
To better highlight the short-term effects of fuel prices on market value and value factors of different wind technologies a different approach would be more suitable: simulating only the dispatch withouth the possibility for the system to adapt by means of investments.

Part IV

Discussion & Conclusion

11

Discussion

11.1 Results recap

Design of turbines The results of the analysis showed that reducing SP to the level of the newly announced wind turbine models, namely 200 W/m^2, has a higher impact on both the system and the market value of wind than the respective evolution in hub heights to 150m.

Reduced total system costs The total system costs are reduced in case of advanced SP designs, mainly due to the reduction of total capital costs. In Sp200 and in the year 2030, the total system cost is reduced by 6 billion € compared to Sp300 and 10 billion € compared to Sp400, corresponding to roughly 1.3% and 0.8% reduction respectively. The main drivers for the CAPEX reduction are the lower capacity in the system of both wind power and peak power plants.
Even when assuming a 20% higher capital cost for turbines rated 200 compared to 400 W/m^2, the large reduction in the wind capacity needed to reach a certain penetration level outweighs the cost top-up. Additional savings are related to fuel costs: Sp200 features higher baseload production such as nuclear and lignite, which have lower fuel costs. On the other hand, Sp400 has much more natural gas production, causing an increase in the fuel expenditures.

Increased market value of advanced designs The results and the sensitivities confirm a large difference in the VF of different SP technologies . In 2030, with an onshore wind share of roughly 31% in Germany, the difference in the value factors is in the range 0.18-0.23 for the simulated fuel and CO_2 prices. This corresponds to the wind generation in 200 W/m^2 scenario being 30% more valuable in the market than in the 400 W/m^2 one.
This value gap is even larger compared to what was assessed in a previous study [8], namely 15% difference in the bulk value of advanced wind power at 30% wind penetration rate. The most important reason for this difference is that simulations carried out in [8] were considering long-term equilibrium in terms of both generation and transmission, disregarding the actual system in place today and the planned projects, while letting the system invest in the optimal configuration.

Not only new installations, but also existing wind assets would benefit from the reduction of the SP of new turbines, due to a increased diversity in production patterns. The new turbines would indeed produce in different hours and reduce the merit-order effect at hours of high wind. Existing onshore fleet showed an absolute increase in the value factor of 7% in 2020 and 11% in 2030 in Sp200 compared to Sp400.

Even if no change is considered in the model regarding offshore technology, it is positively affected in terms of revenues when onshore goes lower in SP, due to the reduction of the *self-cannibalization* effect. However, the magnitude of the change is small and its value is already much larger than onshore.

Systems with access to large hydro Even with larger penetrations of wind power, the value of wind in countries with access to hydro such as Denmark showed to be higher compared to thermal power systems like Germany, corroborating previous results described in [38]. This is particularly true for scenarios with higher specific power. When reducing SP, the difference of value factors between Germany and Denmark decreases as well, confirming that a system-friendly wind reduces the need for a wind-friendly system.

Importance of the subsidy scheme design The highest impact on the value factor among the sensitivity simulations performed is given by the subsidy level for VRES, more precisely to the way it influences the dispatch.
Not paying subsidies at negative prices to solar and wind, thus avoiding the price to be set at a negative level in many hours, reduces the benefit of lower SP in terms of increased market value in 2030. The absolute value gap for onshore wind is in this case reduced from 0.20 to 0.15.

Increased merit order at low wind speeds for low SP technologies The previous study on the topic [8] focused on the reduction of merit-order effect at high wind speeds due to the use of low SP turbines. In this study, a new dynamic has been underlined: in case of an evolution of fuel and CO_2 prices that causes the steepness of the supply curve to increase, lower specific power technologies can drive merit-order effect at low winds and reduce the market price. This way, their advantage with respect to higher SP is partially reduced.

11.2 Modelling observations

Number of market zones

In the analysis, Germany has been modelled with different price zones. While splitting Germany into different market zones allows for a consideration of internal bottlenecks, it has the downside of creating fictional price zones which do not reflect the potential EPEX market outcome.
This affects the resultant value of wind and enables to draw socio-economic conclusions, but the results are less strong from an investor perspective, due to the mismatch with EPEX market setup. However, the difference compared to a single market zone is reduced over time thanks to the progressive overthrow of bottlenecks, with the results on 2030 being supposedly closer to reality.
The effect was shown to be more considerable in regions like DE-NE, where most of the capacity is from renewable sources such as wind and PV and therefore the market zone outcome in terms of prices is largely affected.

Overestimation of value factors

When comparing historical value factors with the ones resulting from the model for the year 2015, it is clear that a mismatch is occurring. In particular, the modelled VFs are always higher than the realized ones. For example, in 2015 the historical VF for Germany and Denmark were 0.85, while the resultant ones for the 2015 dispatch simulation were 0.93 and 0.95 respectively.
On the other hand, the average annual prices are close to the realized ones. Since price levels are in the correct range and wind production is calibrated to fit the historical one, there must be a discrepancy with the shape of price duration curves.

Figure 11.1 shows, for the year 2015, a comparison of price duration curves from the model (different German regions) and the historical one from EPEX spot, calculated using data from [1].

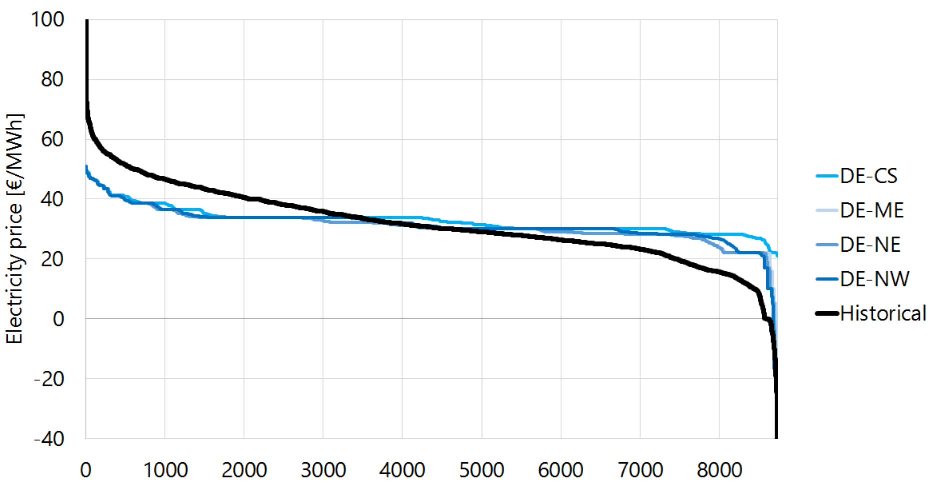


Figure 11.1: Difference in the price duration curve between real market data and modelled results, year 2015.

From this figure, it is evident that the price duration curves in the model are much more flat, with a higher price in the low end and a lower price in the high end. Such a flat curve is the main reason for the overestimation of VFs. Indeed, wind sees a higher price compared to reality when producing more and a lower price when wind generation is less. The same behavior is revealed for Denmark.

The reason for this mismatch in the price results is related to the imperfect nature of dispatch optimizations, which cannot capture the full picture of marginal costs and in particular the strategic behavior of some producers, mainly hydro power ones. Indeed, the imperfect knowledge proper of real operations, a certain level of market power and the speculative behavior of hydro would supposedly make the price duration curve steeper.

Other reasons that could contribute to the overestimation are:

- the capacity of European countries (other than Germany and Denmark) is updated to end of 2013, thus there is more RES capacity in the system than the one simulated
- even though technologies with different efficiencies are modelled, the level of detail is not at a single plant level
- wind is modelled to be representative for a normal wind year, while 2015 was a very windy year with 13% more wind production than a normal one. Higher wind production would lead to a lower VF, thus reducing the overestimation
- only a general seasonal variation of natural gas is modelled, while for the rest of the fuels the price is one throughout the year. This has a large impact especially for a year like 2015 in which very large price fluctuations took place
- in an economic dispatch simulations, no start-up cost and no ramping of conventional power plants are included.

The overestimation of the market value with respect to the average price was already observed in [34], which uses he same model, namely Balmorel, even though with a different model setup.

To conclude, even though there is a tendency to overestimate value factors in the model, the results can still be considered significant in terms of comparison between different scenarios or differences across years.

11.3 Limitations of the analysis

Different wind years

Balmorel model setup and consequently the one of this study, is meant to reflect a normal wind year, i.e. a year with average wind resource. The choice and the simulation of a different years in terms of resource quality is time-consuming and not simple to implement. Two are the main reasons: correlation of wind profile with other time-series in the model and large amount of calibration performed on wind-related input parameters.
In reality, wind years can largely differ from a normal one. In fact, according to [93], the wind index reported for Denmark in the last ten years has varies in the range 0.9-1.13. This variation is not simulated in the present study.

Lack of unit commitment

The analysis carried on in the thesis is based on economic dispatch (ED) simulations. The downside of ED is that no constraints related to minimum load, minimum/-maximum up and down time and ramp limitations of the power plants are included in the formulation. Therefore, the scheduled dispatch could potentially result infeasible due to technical limitations of the power plants. For example, a large change in wind power from one hour to the next could require a coal power plant to quickly adjust its production. No limits to how large the output variation of the coal power plant are included in the ED simulations.
Moreover some cost components, such as start-up costs, are not taken into account in the definition of the variable cost of the unit, while in reality those costs are somehow reflected in the bid from the producers in the market.

All these information and constraints are included in the formulation of a Unit Commitment problem (UC). The UC better describes the technical dynamics of power plants bidding into the market and the related costs, potentially increasing the diversity of price profile and reducing the difference between real and modelled price duration curves. Its downside is related to the very high computational time. Indeed, in order to represent the online status of plants, the formulation of the optimization include integer variables, transforming the Linear Programming (LP) problem into a Mixed Integer Programming (MIP) one.

For a study with a large scope like the present, both in terms of geographical extension and the need for investments optimization, the use of UC is not feasible from a computational time perspective.

Perfect foresight of wind and other parameters

The model optimizes dispatch and investments in a deterministic way, having perfect foresight about the realization of uncertain parameters such as wind production patterns, hydro inflows and demand levels. In reality all these parameters are subject to uncertainty, which affects both the dispatch in terms of market outcome and the investments in terms of reserve requirements needed to balance supply-demand mismatches.

Stochastic formulations of both ED and UC have been developed in literature in order to take into account the uncertainty related to different parameters, in particular wind and solar generation. Including stochastic representation in dispatch and investment problems requires a much higher computational time and it is not included in the current Balmorel model setup.

11.4 Additional considerations

Dedicated incentives and support schemes

Given the advantages for the system of reduced specific power and higher hub heights, subsidy schemes could be designed to drive investors to choose more system-friendly wind designs.

When dealing with support schemes, it is important to underline that they have to ensure a total or partial market exposure in order to avoid distortions to the design of turbines, consisting for example in maximizing the capacity or output of the turbines, rather than optimizing the participation to the market [34].
An example of this potential distortion is related to the incentives based on a total number of FLH. Indeed, when space is a limitation, which is the case for onshore wind, incentivising a certain amount of FLH could induce investors and planners to oversize the capacity of a plant in order to get the maximum total incentive possible, rather than focusing on optimizing the design for minimizing LCoE or the market participation. Typical subsidy schemes ensuring a partial level of market exposure are feed-in premiums and green certificate obligations. Instead, under fixed feed-in and sliding (also called floating) premiums allocated with auctions, the reduced market value of wind results in an increased cost of subsidies. Therefore, under those support schemes impermeable to price signals, the reduced market value becomes an externality [4].

In Denmark, a new support scheme for onshore turbines has been introduced in 2014 [107]. The subsidy is now not only paid based on the FLH of the turbine, but a top up is added based the size of the rotor in terms of m^2, which provides a direct incentive to reduce the specific power. Whether this is enough to influence investments in the right direction is still to be determined.

In Germany, the setup for floating market premium remuneration outlined in the EEG14 [28] offers an advantage for investors to go lower in SP 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 onshore wind is considered. A producer which has a lower SP turbine and already sees a higher price in the market will receive the same remuneration as another onshore plant with a higher SP, thus increasing its income. An analysis of investment behavior [17] has showed how this support scheme alone fails 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 policy-maker perspective, but it is probably not enough to drive a significant change in investment decisions. Indeed, the two largest limits for investors to take actions in this direction are imperfect foresight and financing constraints [17]. In this perspective, a right subsidy design is probably necessary in order to impact advanced turbine deployment.

Awareness of investors and policy-makers: LCoE vs. Market Value

Beside the need for a specific subsidy schemes, the first step toward a reduction of SP is probably to increase the awareness of project developers for the risk implied by the future decrease of market values. Investors, which usually have a time horizon of 20-25 years (lifetime of wind assets), should pay more attention to the value of wind and make decisions based on the value of output compared to its cost, especially in a system in constant evolution. In such a changing environment, cost minimization alone could fail to trigger optimal investement decisions.

The importance of considering economic design criteria to help a system-friendly development of variable RES is stressed in one of the latest reports from IEA [108], as a means to achieve both a better integration and a higher system value.

Trade-off between increased cost and increased value

Further studies on the trade-off between the cost increase of lower SP turbines and their additional market value are needed to understand the optimal investment choices and the way these could be affected. On the one hand, in areas with lower average wind speeds, it has to be understood to what extent does it pay off to increase the rotor blades to see a higher market value, while incurring higher capital costs. On the other hand, in more windy areas, it has to be assessed what is the optimal specific power deployment in terms of generator size reduction, which is justified by the progressive and fast decrement of market value at high wind speeds.

Due to lack of cost data on advanced turbines and the variety of designs for a certain specific power, such a trade-off assessment could for example be approached with a threshold analysis, through a Balmorel investment run where the model is free to choose different SP technologies with the related costs. The question to be answered would be:
What is the maximum extra cost of a technology with lower SP in order for the model to choose that compared to the ones with higher SP?

One of the modelling challenges related to this approach, which has justified the postponement of the analysis as a further research, was related to time resolution. While investment runs need more aggregated and lower time resolution due to computational burden, a correct quantification of the value of wind needs an hourly resolution dispatch. An investment run, which has to choose a technology based on its market value, would lay in the middle of these opposed goals and a dedicated approach has to be developed.
An option could be simulating with full resolution some representative weeks in terms of wind and demand (e.g. combination of wind and demand levels), while performing some correction in order for them to be representative for an entire year.

12

Conclusion

The last few years saw a large development in the wind turbine technology. Particularly in Germany, hub heights of new installations are increasing rapidly and latest models have reached 150-160 meters. Moreover, the growth of rotor diameters outpaced the one of rated power, resulting in a decrease of specific power. New wind turbine models designed specifically for onshore conditions are down to less than 200 W/m^2. The reduction of specific power was very strong in the United States and less pronounced in Europe, where large room for a further reduction is present.

Motivated by these recent developments, the present study was aimed at analysing the effects of turbine design in terms of specific power and hub height on the power system. Special focus has been placed on system impacts and total system costs, as well as on the market value of wind power. A new method to model future wind generation based on aggregated and smoothened regional power curves has been proposed and used in the context of Balmorel model.

The impact of deploying the advanced turbines in terms of lower specific power has been shown to be much larger than for advanced level of hub heights. Considerable benefits have been highlighted by the reduction of specific power for both society in terms of total system costs and for private investors in terms of market value of wind.

A scenario projecting the use of turbines with a specific power of 200 W/m^2, has shown a decrease in the total system costs in 2030 by 1.3% (10 billion €) compared to the deployment of 400 W/m^2 and by 0.8% (6 billion €) compared to 300 W/m^2. Other system advantages relate to lower fossil fuel capacity installed, large reduction of curtailment and renewable surplus, increase of wind capacity credit and reduction of the steepness of residual load duration curves.

From a market perspective, a very large difference in the value of wind has been underlined. In case the specific power of turbines maintains the level of today's high end, namely 400 W/m^2, the price that onshore wind power sees in the market would be 31% lower than the average wholesale electricity price in 2030, corresponding to a value factor of 0.69. Additionally, if considering that economic dispatch models have been showed to overestimate the value of wind, the figure could in reality be even lower. The choice of low specific power turbines increases the value of wind by 30% in the German power system in 2030 across different fuel and CO_2 price scenarios, resulting in a market value not far from today's level even at roughly 31% onshore wind penetration. The result is higher than previous works considering a long-term perspective and a green-field optimum power system.

Subsidy schemes design has revealed a major impact on the value of wind. If measures will be taken to avoid renewables to produce at negative prices, the advantage of low specific power would be down from 30 to 22%. Moreover, the advantages at a system level could in the future motivate dedicated incentives for lower specific power, following the example of Denmark. An alternative for such direct incentives is exemplified by the German design of floating premiums. The advantage of more system-friendly solution is related to the way the subsidy settlement is calculated, resulting in an increased awareness of investors for the value side of the electricity generated. Deepening such a discussion about support schemes is a topic for further research.

The result of this study could be used to understand the trade-off related to the market value of wind and the cost of turbines, as part of the continuation of the research in the framework of WP4 of IEA Wind Task 26. For instance, the optimal specific power deployment in high wind speed areas in terms of generator size reduction justified by the projected decrement of market value at high wind speeds. Moreover, the outcome of projects like the present can help policy-makers to better understand the system benefits of different wind turbine technologies and design support schemes accordingly, as well as increase the awareness of investors regarding the future decline in the value of wind generated and the technological options which can help mitigating it.

As a final recommendation, opting for economic design criteria when investing in wind power and switching from a cost to a value perspective can have positive impacts for both private stakeholders and society as a whole.

13

Future works

Short-term effects of fuel prices in the value of wind

Assessment of the short-term impact of changes in fossil fuels and CO_2 price on the dispatch and how could this affect market value of wind power across different technologies. A short-term perspective implies to run only dispatch optimization and consider the same system in terms of installed capacities.

Trade-off between different technologies

Analysis from an investor perspective of the trade-off between increased cost for lower specific power and additional market value. A general analysis based on Balmorel results and the previously described investment run with technological options, as well as insight into optimal reduction of generator size depending on the market value in the most windy hours.

Support schemes design for specific power reduction

Study how the design of support schemes can influence the decision of investors in terms of specific power reduction. First of all by looking at the results in Denmark after the introduction of the rotor size subsidy top-up. Consequently, better understand the functioning of other support schemes with respect to market value considerations, such as CFD remuneration in Germany.
Finally, understand if and to what extent it could make sense to incentivise specific power to reflect the benefits at a system level underlined in this study, given that a direct incentive is given to investors by the projected reduction in their market income, following the increase of wind penetration.

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Part V

Appendix

A

Balmorel Model Structure

Structure

The structure of Balmorel model is described in detail in [109]. There are three main dimensions in the model: Time, Geography and Technology, with the following subdivisions, representing the sets:

Time	Geography	Technology
Years (Y)	Countries (C)	Tech (G)
Seasons (S)	Region (R)	
Times (T)	Areas (A)	

Time The simulation flow follows predefined time steps. It will proceed one Year at a time, utilising the corresponding data for the respective year, including annual demand as well as available generation capacity for electricity and heat. Each Year is split up into Seasons with a desired resolution of usually 4 (seasons of the year), 12 (months) or 52 (weeks) segments. The highest level of detail is represented by the subdivision into Times, which represent an hourly resolution. This is used for simulating fluctuations of potential electricity generation from wind, hydro and solar power by means of utilisation profiles (% of installed capacity) as well as demand fluctuations by means of a load profile. For each time step, the simulation will determine and output a least cost solution.

Geography The model permits specification of geographically distinct entities. The types of geographical entities are Areas, Regions, and Countries. Each country is constituted of one or more regions while each region contains zero or more areas. Any area must be included in exactly one region, and any region must be included in exactly one country.
Electricity balances are given on a regional basis, while heat balances are fulfilled in every area.

Balmorel regions for the European system are shown in Figure A.1.

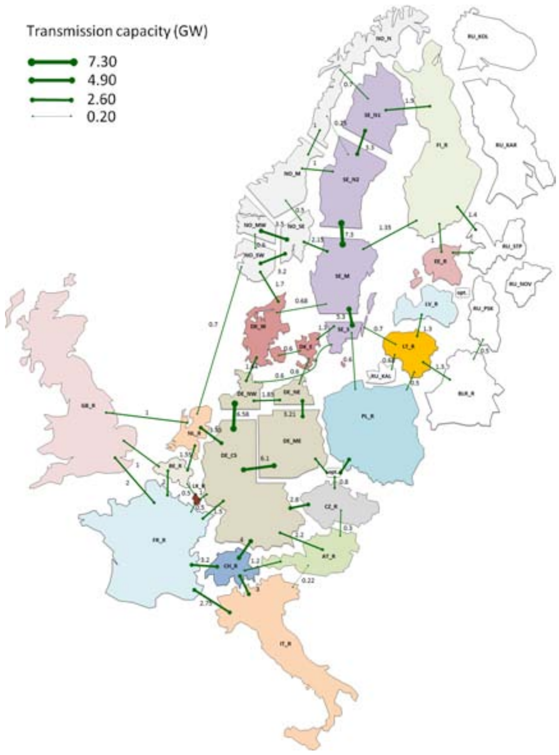

Figure A.1: Geographical scope of the model. Balmorel regions in Europe with their interconnections in 2015.

Technology Balmorel distinguishes between 13 types of units for the generation of heat and electricity. Technologies are specified by the following technological and economic specifications: Fuel type, Electrical efficiency, C_b and C_v value for combined heat and power production, Emissions, CAPEX and OPEX.

Different options for model runs

The model include the possibility of running different kind of optimization. The two runs that are relevant for this study are presented below:

- **BB1 - Operation Optimization with yearly resolution**: this option for the model resolution is the most simple and basic. The linear problem is solved by optimizing operations and dispatching the cheapest generations. The capacity installed is an exogenous parameter.
- **BB2 - Operation and Investment Optimizatio**: includes in the model 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 more profitable.
- **BB3 - Operation Optimization with weekly resolution**: equivalent to BB1, beside the fact that 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 lies in how hydropower optimizes its operation, having a much lower time horizon of perfect knowledge.

B

Additional inputs

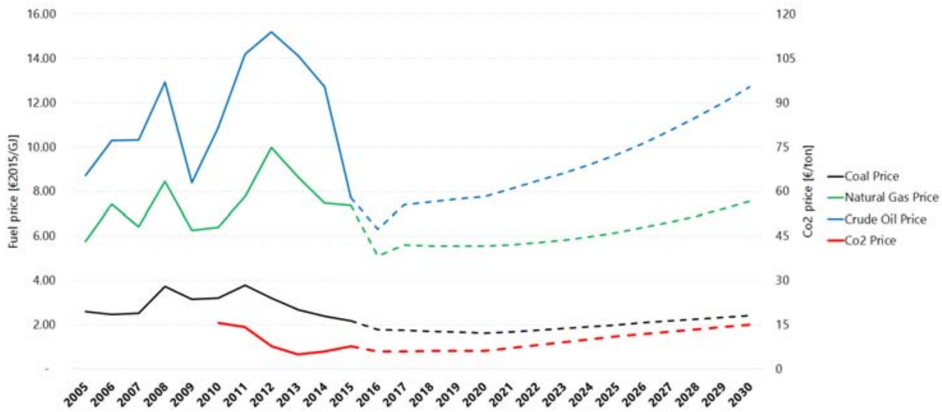

Figure B.1: Fossil fuel and CO_2 prices assumed in the model, expressed in 2015-€/GJ. Various sources.

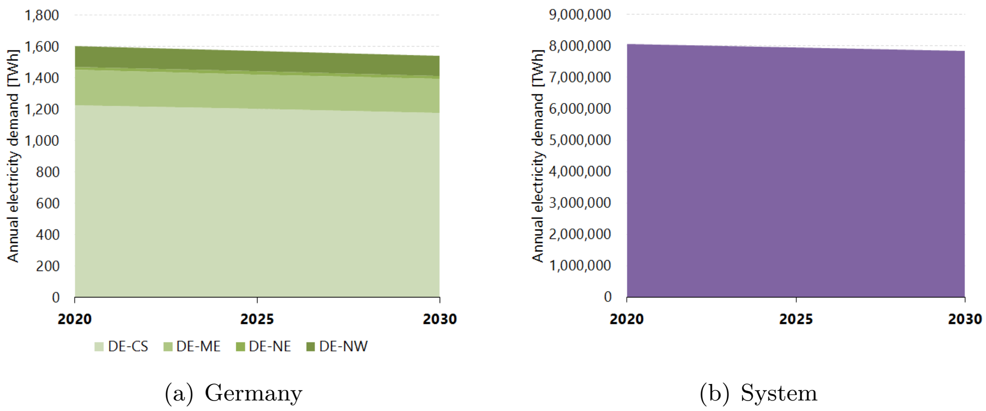

Figure B.2: Development of power demand in Germany **(a)** and the entire system modelled **(b)**. Various sources.

C

Hub height Scenarios results

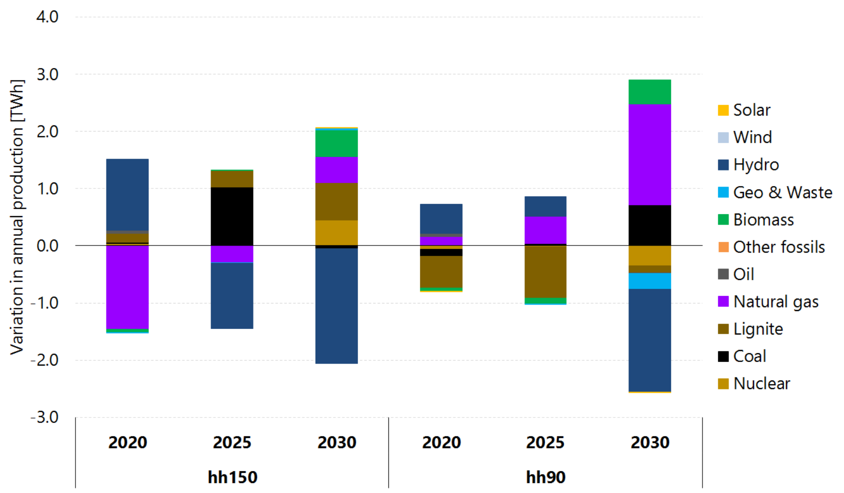

Figure C.1: Variations of annual generation in hh150 and hh90 compared to hh120.

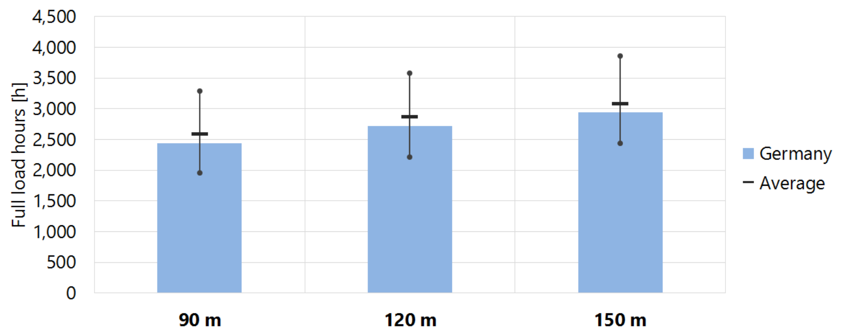

Figure C.2: FLH for different HH at 300 W/m2 specific power.

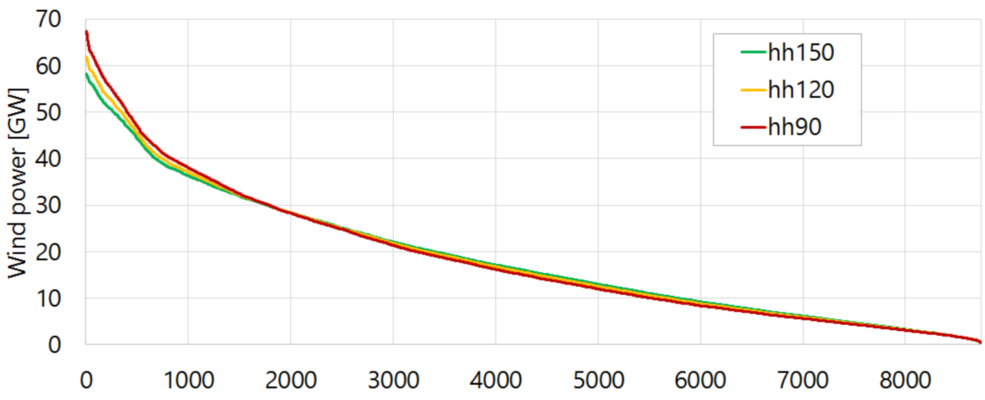

Figure C.3: Total onshore wind in Germany. Change in the duration curve across HH scenarios in 2030.

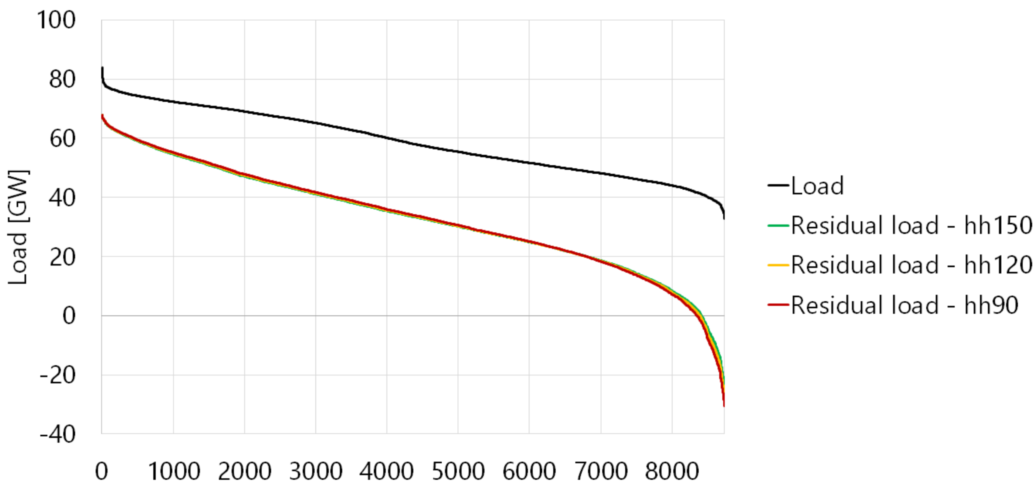

Figure C.4: Residual load duration curve (load minus wind power) in 2030 for the three HH scenarios.

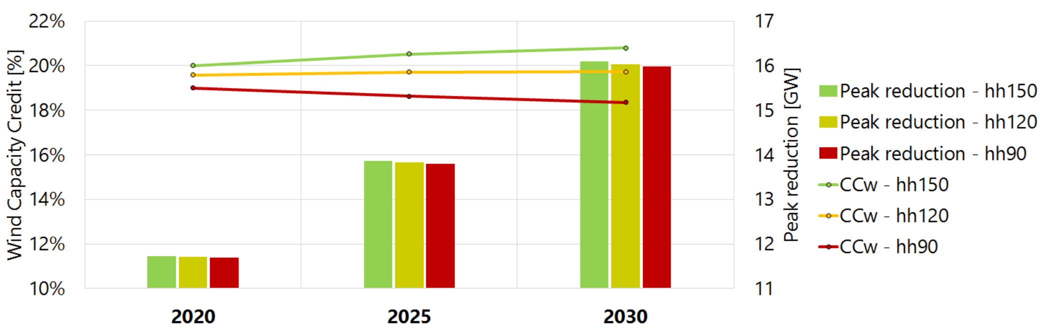

Figure C.5: Capacity credit (left axis) and reduction of the peak capacity (right axis) in the different HH scenarios.

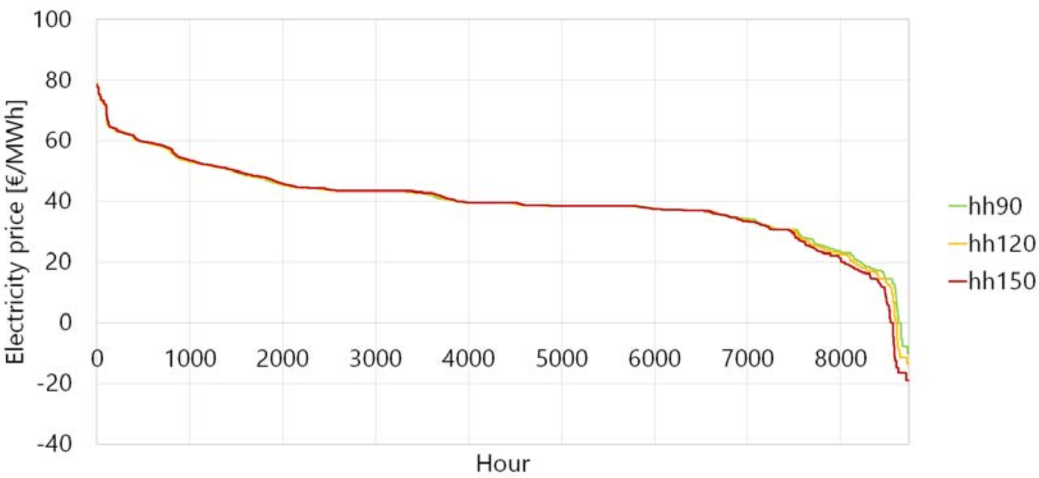

Figure C.6: Price duration curves in different HH scenarios for the region DE-NW in 2030.

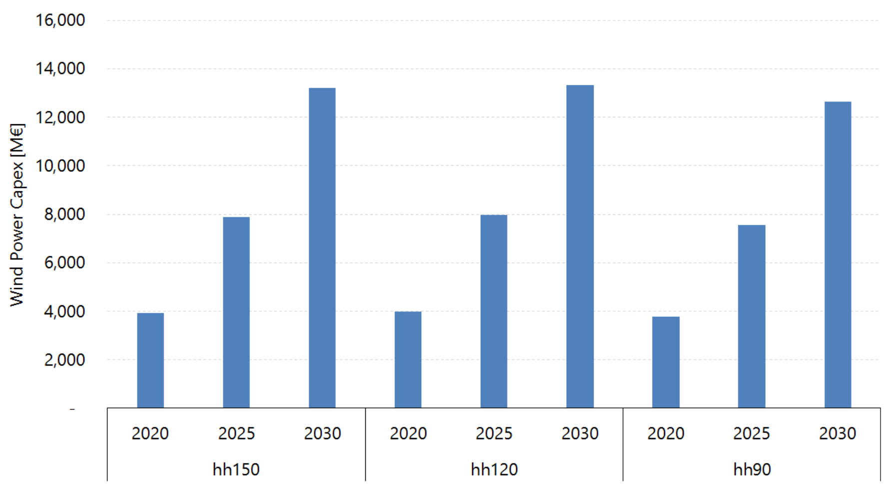

Figure C.7: Total CAPEX for the entire system of new wind installations in different HH scenarios. hh120 shows the maximum total CAPEX across scenarios, meaning that the reduction of capacity compared to hh90 is outweighed by the additional specific installation cost.

Year	Scenario	Capital Cost	Fixed O&M	Fuel Cost	Variable O&M	Emission Cost	Other costs	Total costs
2020	**hh150**	640,760	90,412	28,874	8,270	5,416	78	**773,811**
	hh120	640,698	90,479	28,929	8,274	5,419	-	**773,798**
	hh90	640,099	90,579	28,923	8,272	5,415	38	**773,325**
2025	**hh150**	641,023	90,666	29,307	8,018	8,118	-54	**777,078**
	hh120	641,070	90,803	29,309	8,014	8,109	-	**777,304**
	hh90	640,333	91,008	29,309	8,014	8,101	51	**776,815**
2030	**hh150**	642,873	92,467	24,546	7,748	7,786	38	**775,458**
	hh120	643,167	92,727	24,501	7,740	7,774	-	**775,907**
	hh90	642,699	93,042	24,631	7,733	7,791	6	**775,902**

Table C.1: Total system costs and different cost components expressed in M€-2015 for the different HH scenarios.