Charles University in Prague

Faculty of Social Sciences

Institute of Economic Studies

Cost Benefit Analysis of Wind Power in Germany

Author: Bc. Nazariy Labunets

Supervisor: Ing. Mgr. Miroslav Zajíček MA, PhD

Academic Year: 2013/2014

Declaration of Authorship

The author hereby declares that he compiled this thesis independently, using only the listed resources and literature, and the thesis has not been used to obtain a different or the same degree.

The author grants to Charles University permission to reproduce and to distribute copies of this thesis document in whole or in part.

Prague, January 6, 2014

Signature

Acknowledgments

I would like to thank my supervisor Miroslav Zajíček for the time dedicated to consultations, guidance, and ideas to keep me going during the lengthy preparation of this thesis. I would also like to thanks my wife Sevilia for her constant support and understanding, and my parents Galina and Leonid for their expectations, temperate pushing, and setting the bar high.

Abstract

The objective of this thesis is to perform a cost benefits analysis of the wind power sector in Germany, with the horizon of 2030. Various costs and benefits stemming from the expansion of wind power are inferred from literature review and studying the peculiarities of the German case. The magnitude of governmental support is calculated by applying the Weibull distribution of wind at different zones across Germany and power curves of 5 modern wind turbines, as specified by the law. A number of sensitivity analyses is performed on the main inputs for onshore installations. Under the baseline assumptions, the onshore sector is found as non-beneficial to the society, without a visible improving trend for the future. While the offshore sector does not reach a point where the benefits would start overweighing the cost until 2030, the overall trend look much more promising.

JEL Classification	H23, L94, Q42, Q48
Keywords	Environmental Subsidies, Electricity Sector, Alternative Energy Source, Wind

Author's e-mail	nazar.labunets@gmail.com
Supervisor's e-mail	miroslav.zajicek@vse.cz

Contents

Table of Figures

Table of Tables

Master Thesis Proposal

Institute of Economic Studies
Faculty of Social Sciences
Charles University in Prague

Author:	Bc. Nazariy Labunets
Supervisor:	Ing. Mgr. Miroslav Zajíček MA, PhD
Defense Planned:	February 2013

Proposed Topic:

Costs of Support for Wind Power Plants in Selected European Countries.

Topic Characteristics:

Renewable energy is an important item on the European Union's agenda. The current goal is to increase the share of renewable energy in the EU energy mix to 20% by 2020. Such biding target has been adopted by EU Heads of State in March 2007. Besides that, a 20% energy efficiency increase and 30% reduction in CO2 emissions are planned to be achieved by the same year. Therefore, development and expansion of renewable energy is seen as an integral part of reaching the two latter goals.

In this thesis we will focus on the wind power sector, which is one of the fastest growing renewable energy sources in the world and EU. For two years in a row (2008, 2009) wind power was a leading renewable energy source by the number of new installations, with only a 10% decrease in 2010. The annualized growth rate over the period from 1995 to 2010 was 17.6%.

Because wind power (and other renewable energy sources) cannot compete with conventional sources in the open market and for its faster development, wind power projects are heavily subsidized. Such government support is not eagerly embraced by all, and discussions around wind power are heated and controversial. Discord extends to such fundamental issues as whether wind power presence reduces energy prices or increases them, whether CO2 emissions decrease or increase because of it, and whether the presence of wind turbines reduces the number of conventional plants needed to be in operation.

These issues question the expedience of the massive government support for wind power on the whole. This thesis will try to estimate the costs of government support for wind power in selected European countries. Projections will be made 10 and 20 year ahead and presented in different forms. Then conclusions will be made about the viability, relevance, and cost-efficiency of wind power in the selected countries.

Hypotheses:

1. Subsidies from the government are smaller than net benefits of wind power integration.
2. Presence of wind power in the electricity supply system brings savings to households.
3. Wind power is more cost-efficient than conventional power sources.

Methodology:

To calculate the costs of government support in selected European countries, information on capacities of wind power in those countries will be collected. By applying the relevant capacity factors of wind farms in the selected countries, the potential output will be calculated. Then specific government incentives and subsidies will be applied to them, e.g. feed-in tariffs, production tax credits, application of favorable depreciation schedules, property tax reductions etc.

Predictions will be made about the development of wind power in the selected European countries, and CO_2 and fuel costs till 2020 and 2030. Countries' forecast documents on renewable energy submitted to the European Commission will also be reviewed and analyzed. Besides that, costs related to the expansive grid infrastructure enlargement will be computed.

After a thorough research into the nature of wind power (especially its intermittency), assumptions will be made about its CO_2-reduction capacity. After a thorough literature review, assumptions will also be made about the electricity price-reducing capability of wind power integration. Subsequent relevant computations will be made in order to obtain numerical financial result of both capacities. Conclusions will be made about possible savings to households due to the wind power presence in the electricity supply system.

Cost-benefit analysis will be performed on wind power and conventional power sources based on previous calculations. Sensitivity analysis may then be performed with various scenarios of CO_2 and fuel costs, and also different penetration levels of wind power.

Outline:

1. General Overview of Wind Power Trends in the European Union.
2. Development of Wind Power in the Selected Countries.
3. Overview of Support Schemes in the Selected Countries.
4. Predictions for 10-20 Years and Assumptions.
5. Cost Computation and Hypothesis Testing
6. Results.
7. Conclusions.

Core Bibliography:

"Energy: Forecast Documents - European Commission." Web. 7 July, 2011. <http://ec.europa.eu/energy/renewables/transparency_platform/forecast_documents_en.htm>

European Wind Energy Association, 2008. "Pure Power: Wind Energy Scenarios up to 2030."

Holttinen H, 2004. "The Impact of Large Scale Wind Power Production on the Nordic Electricity System." PhD Dissertation, VTT publications 554, Espoo, Finland.

Nuclear Energy Agency, International Energy Agency, 2010. "Projected Costs of Generating Electricity. 2010 Edition." Nuclear Energy Agency, IEA, OECD, Paris.

Tzimas, E. A Georgakaki, S. D. Peteves, 2009 "Future Fossil Fuel Electricity Generation in Europe: Options and Consequences", European Commission Publication, JRC Reference Report

Van Kooten, G.C. and G.R. Timilsina, 2009. Wind Power Development: Economics and Policies. Policy Research Working Paper 4868. Washington, DC: World Bank.

Author

Supervisor

1 Introduction

Renewable energy is an important item on the European Union's agenda. The current goal is to increase the share of renewable energy in the EU energy mix – or final energy consumption – to 20% by 2020, which currently stands at 13% (Eurostat, 2013). Such biding target has been adopted by the European Parliament on December 17th, 2008 (Parliament, 2008). Besides that, a 20% energy efficiency increase and 20 to 30% reduction in CO_2 emissions are planned to be achieved by the same year. Therefore, development and expansion of renewable energy is seen as an integral part of reaching the two latter goals.

This thesis focuses on the wind power sector in Germany, one of the European leaders in the expansion of this renewable energy source. This country, in particular has the aim of reaching 35% share of renewable energy generation by 2020 and 50% by 2030. Wind power will play a major role in reaching these goals. Since renewable energy in Germany is supported by the feed-in tariff, this puts tens of billions of euros at stake for wind power alone.

In particular, the objective of this thesis is a cost benefit analysis of the whole industry until 2030, separately for onshore and offshore installations. Various costs and benefits stemming from the expansion of wind power are inferred from literature review and studying the peculiarities of the German case. The magnitude of governmental support is calculated by applying the Weibull distribution of wind at different zones across Germany and power curves of 5 modern wind turbines, as specified by the law. A number of sensitivity analyses is performed on the main inputs for onshore installations.

The thesis is structured as follows: Chapter 2 gives an overview of the wind power sector in Germany and provides the overview of the feed-in-tariff system. Chapter 3 reviews the costs and benefits used in this thesis, and provides the main assumptions and values. Chapter 4 specifies the two main scenarios used: optimistic and pessimistic. Chapter 5 describes the methodology used to calculate the amount of governmental support. Chapter 6 presents the results and sensitivity analysis. Conclusions and discussion are presented in Chapter 7.

2 Wind Power in Germany

2.1 Germany’s Electricity Mix

Since 1990, Germany has been increasing its renewable energy capacities and electricity production. Since that time and until 2012, the share of renewable sources has grown from 3.6% to 22.6%. This can been seen in the graph below. The remaining share of production comes from coal and lignite, natural gas, and nuclear sources, with coal and lignite decreasing from 56.7% and 44.2% while the share of natural gas has grown from 6.5% to 14% (12% in 2012). In absolute number the production has grown from 35.9 TWh to 86.1 TWh (in 2011), more than two times. Natural gas and renewable energy sources are designated to cover for the decrease in the production of electricity from nuclear power since the German government has decided for a complete nuclear phase-out until 2023. Coal and lignite, however, should also cover for nuclear as well provide back-up capacity for wind. This information is summarized in Figure 2.1.

Figure 2.2 shows the development of capacities and production by source in 5-year steps until 2030 as seen in the baseline scenario of the European Commission (2010) report “EU Energy trends to 2030 – Update 2009.” We included wind instead of renewable energy sources (RES) in general into the graph to show its importance in particular since this is the concern of this thesis. The projections clearly show that both coal & lignite and natural will continue to be a big part of the German electricity mix, and renewables, wind in particular, will substitute nuclear energy and provide an increase in production, Germany becoming an even bigger net exporter.

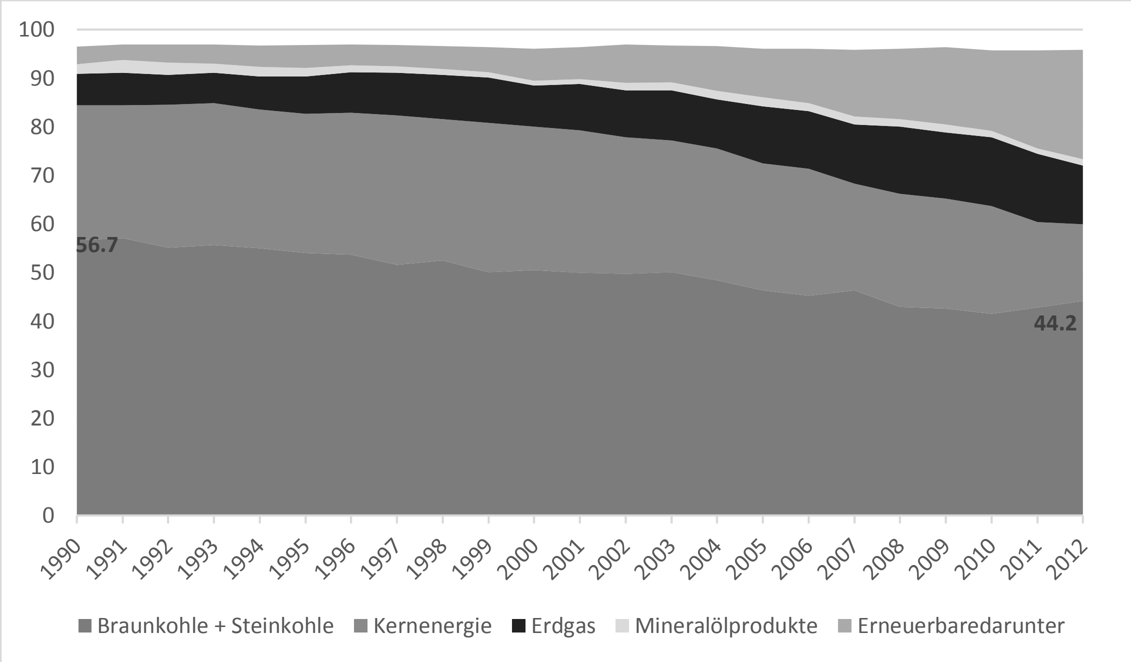


Figure 2.1: Share of Gross Electricity Production by Source Type

Source: Federal Ministry of Economics and Energy (2013)

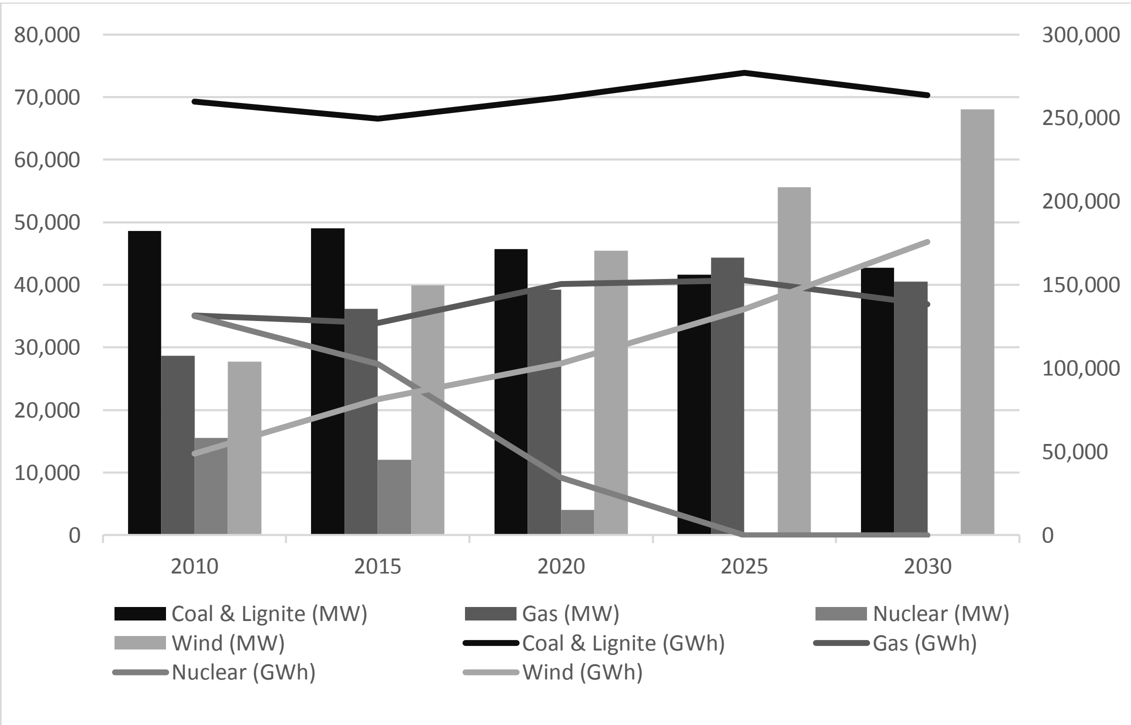


Figure 2.2: Electricity Generation Capacities and Production Development to 2030

Source: European Commission (2010)

2.2 Renewable Energy in Germany

In its National Renewable Energy Plan (Federal Republic of Germany, 2010), Germany is expecting wind power capacity to grow at a compound annualized growth rate (CAGR) of 4.95% in the period of 2011-2020. The produced electricity is expected to double in that period from 49.92 to 104.44 TWh. Wind power's production also accounts for around half of all the energy produced from RES. The CAGR of output for the period is 8.67%, which means that wind power will be getting more and more efficient with years. A recent novelty for the wind industry in Germany is the emergence of the off-shore sector. From having no capacity in 2005, the offshore capacities in 2020 are expected to reach almost 22% of total wind power capacities. This will, of course, be taken into account during the final tariff calculations as the tariffs and conditions for offshore plants are different. Figure 2.3 summarizes the expected development of RES in Germany from 2010 to 2020.

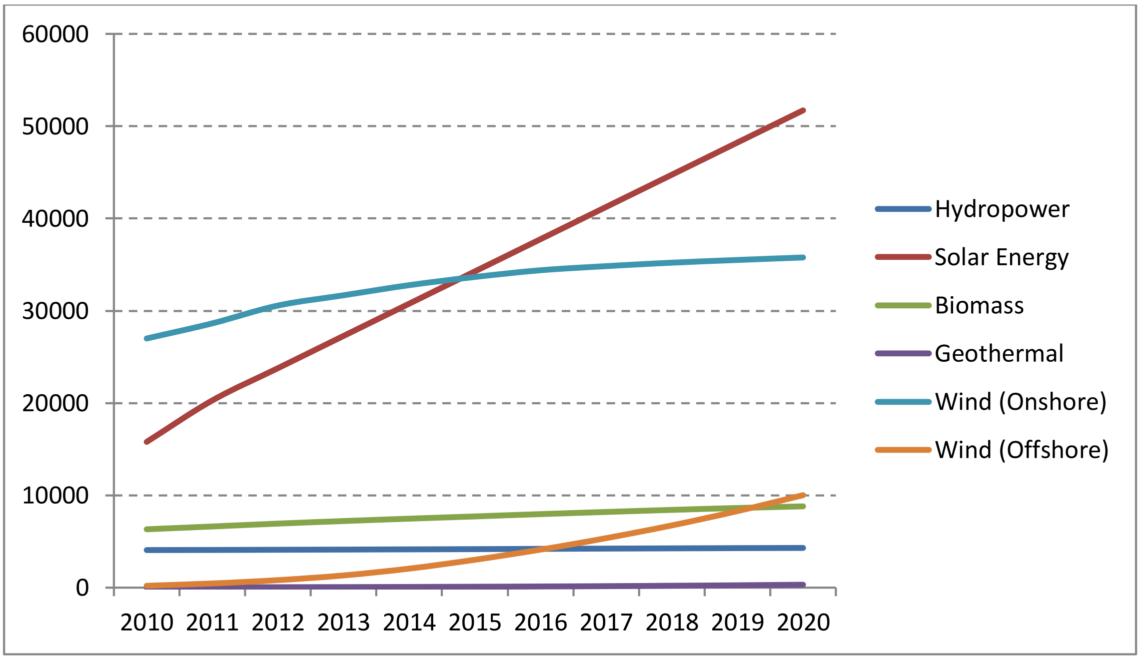


Figure 2.3: Germany RES Breakdown 2010-2020

2.3 Feed-in-Tariff System in Germany

Under the current Renewable Energy Sources Act in Germany (also known as the Erneuerbare-Energien-Gesetz in German or simply the EEG), as amended on August 11, 2010, different rates apply to installations depending on the year of commissioning. In most cases, installations commissioned before 2009 are subject to older rules. The minimum tariffs are paid out for 20 years beginning with the year of commissioning. In most cases, a degression rate is applied. This means installations commissioned this year will have a tariff lower than the last year by the amount of the digression rate. It should be understood, however, that only one tariff is applied to the installations commissioned in a particular year, and there is no reduction in payouts in subsequent years. That is, the tariff is fixed for 20 years depending on the year of commissioning. Other kinds of bonuses or increased tariffs are source-specific. These general rules apply to wind power installations too.

As far as specific rules for wind power are concerned they can be divided into two categories: for onshore wind power and offshore wind power installations. Since the share offshore installations is expected to grow (according to our assumptions) with years and reach more than 37% of all wind-powered capacities in 2030, it is relevant to calculate the support for this type of installations as well, especially in view of the high tariffs guaranteed for them.

2.3.1 Onshore Wind Power

For onshore wind power, two types of tariffs are applied: initial and basic. The initial tariff is higher and is applied, under a default scenario, for the first five years. After that, the lower basic tariff is applied. The initial tariff can be, however, extended up to the full 20 years depending on the installation's reference yield. As defined by the EEG, "the reference yield shall be the quantity of electricity which each specific type of windpowered installation, including its hub height, would, if calculated on the basis of measured P-V curves, yield during five years of operation if it were built at the reference site." The reference site is defined as "a site determined by means of a Rayleigh distribution with a mean annual wind speed of 5.5 metres per second at a height of 30 metres above ground level, a logarithmic wind shear profile and a roughness length of 0.1 metres.” A P-V curve (power-wind speed curve) is a curve that plots the output of a particular turbine at different wind speeds.

Therefore, when deciding by how much the initial tariff will be prolonged, the yield of the installation is compared to its reference yield. In relation to this, the EEG makes the provision that initial tariff will be prolonged “by two months for each 0.75 per cent of the reference yield by which the yield of the installation falls short of 150 per cent of the reference yield.” However, the grid system operator is not obliged to remunerate those installations that cannot prove that they are able to generate at least 60% of the reference yield at the desired location.

Besides the higher initial tariff, onshore installations may be eligible for the system service bonus and the repowering bonus. These provisions will not be applied for the calculations in this paper; therefore, their description will be omitted.

The degression rate applied to the onshore installations is 1.5%. It can be seen in Table 2.1 below, which provides information about tariffs and bonuses. In order to understand better how tariffs for particular plants are calculated, a sample tariff calculation can also be found below. Both have been prepared by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety.

Year of commissioning	Initial tariff in ct/kW	Basic tariff in ct/kWh	System services bonus	Repowering bonus
2009	9.20	5.02	0.50	0.50
2010	9.11	4.97	0.50	0.50
2011	9.02	4.92	0.49	0.49
2012	8.93	4.87	0.49	0.49
2013	8.84	4.82	0.48	0.48
2014	8.75	4.77	0.0	0.48
2015	8.66	4.73	0.0	0.47
2016	8.58	4.68	0.0	0.47
2017	8.49	4.63	0.0	0.46
2018	8.40	4.59	0.0	0.46

Table 2.1: Feed-in-Tariffs for Onshore Installations in Germany

Example 1: Sample Calculation for an Onshore Wind Power Installation

Setting:

Wind energy installation near the coast which pursuant to section 29 subsection (2) produces 120% of the reference yield in a period of five years starting with commissioning (in accordance with annex 5 subsection (2) EEG 2009). The installation meets the requirements set out in the System Services Regulation (Systemdienstleistungsverordnung) pursuant to section 64 subsection (1), first sentence; year of commissioning: 2010.

Calculation:

Duration of payment of the higher initial tariff: **11 years, 8 months**

Calculation: (30 / 0.75) * 2 = 80 (months)

80 months = 6 years and 8 months + five years payment of initial tariff = **11 years, 8 months**

Tariffs	**2010**	**2011**
Higher initial tariff	9.11	9.02
System services bonus	+ 0.50	+ 0.49
Remuneration	**= 9.66ct/ kWh**	**= 9.51ct/ kWh**

Average remuneration: 11.8 / 20 * 9.11 + 5/20 * 0.50 + 8.2 / 20 * 4.97 = **7.54 cent/kWh** (rounded and without degression)

Source: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

2.3.2 Offshore Wind Power

Similarly to onshore installations, remuneration for offshore plants is divided into the higher initial tariff and the lower basic tariff. It is quite evident, however, that offshore installations are given much more support in the period of 2009-2014 than afterwards. This way the development of offshore technologies is encouraged. This is visible in Table 2.2 provided below.

The digression rate is kept at 0% until 2014 changing to 5% thereafter, both the initial and the basic tariff. The initial tariff is provided for 12 years and can be further extended for installations located at least 12 nautical miles in the sea and a depth of no less than 20 meters: “by 0.5 months for each full nautical mile beyond 12 nautical miles and by 1.7 months for each additional full metre of water depth.” To promote commissioning of offshore capacities further, the EEG provides the so called “early bird bonus:” extra 2 cents per KwH for installations commissioned before January 1, 2016.

Year of commissioning	Initial tariff in ct/kWh	Early bird bonus in ct/kWh	Basic tariff in ct/kWh
2009	1	2	3.5
2010	3	2	3.5
2011	1	2	3.5
2012	3	2	3.5
2013	1	2	3.5
2014	3	2	3.5
2015	1	1.90	3.33
2016	3	0.0	3.16
2017	1	0.0	3.00
2018	3		

Table 2.2: Feed-in-Tariffs for Offshore Installations in Germany

3 Review of Costs and Benefits

This chapter presents costs and benefits associated with wind power expansion in Germany. We present all costs and benefits as such which would affect the society in general, not any particular party. In this study we are not arguing whether some benefits or costs actually stem from wind power, but based on the literature review (where applicable), we present their possible magnitudes for the case of Germany. Nevertheless, we do present the current scientific stance on some of the costs and benefits. We also give treat criticism of benefits with doubt. For example, some researchers (White, 2004; Frondel, et al., 2010) doubt that there are any CO_2 emission reduction or fuel savings at all from wind power if additional factors are considered. Similarly, to give an example of arguable benefits, we present a few finding where the presence of wind power in the system might both increase and decrease the price of electricity. Given this information and some of our reasoning, we made an assumption that the price would, after all, decrease. Therefore, we treat costs more strictly than benefits.

3.1 Costs

This section presents the costs associated with wind power expansion in Germany. Three main categories have been identified. First, wind power currently cannot compete with conventional power generators, so it has to be supported in some way. As has been mentioned before, Germany uses **feed-in tariffs** for this purpose. Second, due to the current expansion plans the four German system operators have estimated the need for **grid extension**, and specifically the required investment. Third, due to wind power's intermittent nature, there is a number of additional costs that arise, such as the need for **back-up reserve** and **cycling costs**. At higher penetrations (more than 40% of electricity in the system is produced from wind as defined by Hoogwijk, et al. (2007) there also arise the costs associated with discarded eletricity. For the case of Germany, they are not included because penetrations do not reach such high levels.

3.1.1 Feed-in Tariffs

The first, obvious and straightforward component of the costs side of electricity generated from wind is the governmental support that it gets. We do not need to present the arguments for its inclusion in the analysis because feed-in tariffs are guaranteed for 20 years. The majority of Chapter 5 is dedicated to calculating the amount of feed-in tariffs which will be paid out until 2030.

3.1.2 Grid Extension

While grid extension costs are not incurred directly from producing wind power, their inclusion into the calculation is necessary because the level of penetration of wind power that is expected in Germany in the next 15 years requires new power lines to be constructed. This is true for the analysis of Germany as a separate generating unit, and it would be if such an analysis were performed on a pan-European scale.

The four German transmission operators have estimated that onshore investments until 2023 would amount to around €21 bn (50Hertz Transmission GmbH et al, 2013). The money is needed for connection between the North and South since the northern regions are much more windy than southern. Three main requirements have been formed:

1. Optimization and reinforcement of the existing grid over the length of 4,400 km
2. Construction of 1,700 km of new AC power lines
3. Construction of 2,100 km of new HVDC power lines

As far as the required investment for the offshore capacities, they are similar and amount to around €22 bn. The investment is needed for

“1,720 km of DC grid connection system (1,125 km HVDC lines and 595 km of AC connectors) in the North Sea, and 430 km of AC grid connection systems (370 km AC power lines and 60 km of AC connectors) in the Baltic Sea” (Lang, 2013).

For this thesis, we assume that the aforementioned costs will be incurred equally each year starting in 2014 and finishing in 2023.

3.1.3 Additional Costs

To introduce the next few costs associated with wind power we would like to make an extensive citation of Hoogwijk, et al. (2007) who explain the workings of a power system with exceptional clarity and details necessary for our purpose:

> The main objective of a power system is to satisfy the demand for electricity power efficiently and reliably within certain technical, environmental and economic constraints. This requires day-to-day operation of installed generation capacity in a way that follows the fluctuating demand at the lowest overall costs, within technical and environmental constraints. The basic rule-of-thumb here is the merit order strategy: power plants are operated in order of variable costs. Capital-intensive plants with low operational costs, such as nuclear but also wind and solar power plants, will therefore in principle be operated as many hours as possible, i.e. in the base-load. They may be run the whole year except when taken out for repair and maintenance or due to failure (forced outage). Consequently, they are filling the bottom part of the load duration curve (LDC) of a power system. Intermediate plants are designed to serve the shoulder load, which represents the fluctuations during most of the day. These intermediate plants are usually conventional plants in part-load operation that use a variety of fuels such as coal, oil or natural gas. Sometimes, the demand for power exceeds this base-load and shoulder-load and the system operator has to run plants with excellent load-following capabilities (generation that can ramp at a relatively high rate MW min^{-1}). During these periods and in particular in periods of extremely high demand (peak-load), units with low specific capital costs, quick-start capability and high variable costs due to their low conversion efficiency and/or expensive fuel, e.g., gas turbines or diesel engines are used. Also hydropower or pumped storage plants can be used during these periods. (p. 1386)

Because of wind's intermittency, the reliability of load mentioned at the beginning of the quote above is harder to achieve. As a consequence, additional costs in the form of required investments into back-up capacity and additional spinning reserve arise. In this section we will define and discuss the first of these phenomena.

3.1.3.1 Back-up Capacities

According to the ILEX Energy Consulting's report to the British Department of Trade & Industry, "the intermittency of renewables is the single largest driver of system costs.

(Strbac, 2002).” Indeed, due to its stochastic nature, the presence of wind power capacities has a large impact on the reliability of the transmission system. First, more system operation costs are incurred as more resources are needed to maintain the balance between the demand and supply. Because a continuous balance must be maintained, the system operator has to ensure that there is enough reserve capacity in the system for the cases when wind power (and other intermittent RES) fails to provide the forecast amount of energy. The security of the system, thus, is ensured through other generation capacities (often conventional, like a gas-fired power plant) being ready to compensate for the shifts in the supply from intermittent RES. A study of the German wind power industry by the energy services provider E.ON NETZ mentions that amount of reserve capacities that must be maintained amounts to around 60% of the installed wind capacity. We have now encountered what is known as “capacity credit:” “a measure of the amount of conventional generation that could be displaced by the renewable production without making the system any less reliable” (Denny and O’Malley, 2006). For E.ON NETZ study mentioned above, the derived capacity credit is 100% - 60% = 40%. Hoogwijk, et al. (2007) report that with 5-10% of wind power capacity penetration into a power system, “most utilities accept 20-30% of the installed wind capacity as guaranteed.” Most studies (Denny and O’Malley, 2006; Denny, 2007; E.ON Netz, 2004; Hoogwijk, et al., 2007) agree that with increasing wind power penetration, the need for reserve capacity will grow.

The exact costs of back-up capacities are system-specific and depend on a number of factors (Hoogwijk, et al., 2007):

1. Time characteristics of a power source
2. Characteristics of the conversion technology of a given power source
3. Penetration rate of the power source
4. Characteristics of other capacities in the system
5. Grid characteristics

Simply put, depending on the system, these costs would be higher for systems with less efficient and costly back-up capacities (this also depends on the generation mix, but usually these would be gas-fired power plants) or for systems with high penetration of wind power. Most researchers agree that with increasing penetrations of wind power system reliability decreases and more back-up capacities are needed (Denny, 2007; Giebel, 2000; Hoogwijk, et al., 2007).

3.1.3.2 Spinning Reserve and Cycling Costs

As a consequence of additional reserve requirement, the back-up generators suffer additional costs, the so-called "cycling costs" (Denny and O'Malley, 2006; White, 2004; Denny, 2007). They often have to be run at lower operating levels when there is sufficient supply from wind power generators and switch to higher operating levels when the feed-in from wind power producers is not high enough. Since these conventional plants must be switched on an off from stand-by, their costs per unit of generation rise. The same problem is mentioned by Nicolsi and Fürsch (2009): they say that base load plants have to either ramp down and then up, which will considerably increase their fuel and CO2 costs or simply bid negative prices on the market to get rid of the electricity that they produce. This will be discussed in more detail later on. Besides that, because of non-constant operation cycles, these capacities undergo accelerated wear-out. Their optimal operation schedule on the other hand is continuous. The E.ON NETZ study shows that during a week of strong winds in Germany at territory controlled by E.ON, the difference between minimum and maximum output was 4,300 MW, "equivalent to the capacity of six to eight large coal-fired power station blocks" (E.ON Netz, 2004).

Forecasting of wind power, which could partly reduce the reserve capacities needed to ensure security of the system, is limited to the extent, to which wind forecasting itself is limited, and cannot be relied upon (E.ON Netz, 2004).

We follow Hoogwijk, et al. (2007) and use their estimates of costs which are carried by the installation of back-up capacities and spinning reserve expressed in cents per kWh. Their analysis is focused on costs of wind power under high penetration scenario: more than 40% of all electricity is produced by this RES in the united European framework; however, they provide these estimates for low penetrations as well, and they were used by us for corresponding penetrations in our calculations in Germany. Penetrations were calculated by dividing electricity production from wind in a particular year by the estimate of total production in Germany for that year. Total production numbers were taken from European Commission (2010), specifically the estimates under the Reference Scenario, where wind production are closer to our estimates under the Optimistic Scenario. Additional costs are presented for each year in Appendix A, Table A.4.

3.2 Benefits

This section presents the benefits associated with wind power in Germany. After the literature review we have identified four main benefits.

3.2.1 Electricity Produced

As with costs, we start with simple obvious benefits that wind power brings, which is the electricity produced. After all, the main point of installing a wind turbine is producing electricity, which simply has different environmental characteristics and costs nothing to produce. However, the value for society is the almost the same. We say “almost” because, while wind turbines produce electricity which, while being produced, supplies the electric system, the intermittency vastly discussed above does decrease the value of this electricity. Nevertheless, we do not attempt to estimate what could be the market value of wind electricity and assume that it would be sold (if it was not supported by the FiT) at the average wholesale spot price. Of course, now the price paid for it is above the market price, and by deducting the market price from the feed-in tariff, we calculate the direct “premium” that is paid to the wind electricity producers by the system operators. The only question left (and essentially the main question of this thesis) is whether the remaining benefits which will be discussed in the following sections will overweigh this premium plus the other costs mentioned in Section 3.1.

We take EEX wholesale spot price predictions by Traber, et al. (2011) for calculating this benefit entry. Using their ESSYMMETRY electricity market model they estimate that in 2020 the average inflation-adjusted wholesale electricity price in Germany will be €49.3 per MWh, which a 11% increase over the 2010 price. We extrapolate this increase from 2020 to 2030 and obtain a price of almost €55.

3.2.2 Discussion of the CO_2-reducing Potential

Due to the drawbacks associated with wind's intermittency, there are doubts regarding the CO_2-reducing potential of wind turbines. Although, wind power is in itself CO_2-free, it might implicitly lead to increased emissions from other capacities. When back-up capacities are required to switch on when needed, this will result in increased emissions rate (especially for the cold start-up). For example, when describing the operating experience of introducing a medium-sized wind turbine in the UK, David Tolly of Innogy Plc states that "it has been estimated that the entire benefit of reduced emissions from the renewables programme has been negated by the increased emissions from part loaded plant under NETA" (White, 2004).

However, Denny and O'Malley (2006) show that increased wind capacity penetration can have a positive effect on CO_2 emission reductions, although not for SO_2 and NO_x emissions. Their work also shows that emissions across all three gases are achieved if a tax on carbon is imposed on generators. The third major finding is that reducing the load, that is, demand and consumption, is twice as efficient in reducing emissions as increasing wind power capacities. This means, for example, that reducing the load by 50 MW would be equal to installing 100 MW of wind power capacities. Therefore, for some countries, depending on their energy mix, promoting wind energy is not the most efficient way of reducing emissions.

Fondel et al. (2010) tried to establish whether the rapid growth of wind power capacities in Germany has any emission-reduction effect on a larger European scale. First, they have estimated that the pollution abatement costs from using wind power is 54 € per ton of CO_2 with the 2008 FIT[1]. They compare these costs with the price of the Emissions Trading System (ETS) certificates in the same year, and conclude that it is three times higher (with the maximum historical price being 30 € per ton of CO_2). They conclude that using certificates would be economically more efficient than supporting wind power through the FiT. The authors go even further and argue that there is no real added environmental value at the European level from the extensive support of renewables in

[1] Assuming an emissions capacity factor of 0.584 kg per kWh.

Germany. They say, "As a result of the establishment of the ETS in 2005, the EEG's true effect is merely a shift, rather than a reduction, in the volume of emissions."

This is confirmed by Traber and Kemfert (2007). They modeled the European electricity industry through an extensive set of variables (many of which were missing in the previous research) and looked at the effect of FITs in a decomposed way: through the effect of substitution of conventional power sources by renewable power sources and the price-of-permit effect due to the existence of the ETS. One of their findings is that although the net reduction[2] in CO_2 emissions due to the support of renewables by the FIT in Germany itself is 33 megatons (Mt) of CO_2, the general effect for Europe (due to interconnectedness of some countries to the German grid) is just 4 Mt of CO_2 (negligible). Therefore, they conclude that the government support of RES is ineffective in the presence of the ETS. A reduction in CO_2 emissions can take place only if the overall emissions cap is reduced – again, the effect here is essentially not due to the presence of renewables. The authors suggest that a concerted effort on emissions reduction is needed to achieve a goal of CO_2 reductions.

Nevertheless, since we have included "additional costs" in our calculations, we assume that they comprise these possible increased CO_2 emissions stemming from backup reserve working in suboptimal modes. Therefore, we take the CO_2 reduction numbers from European Wind Energy Association (2011) [EWEA], which can be found in Appendix A, Table A.5. The avoided emissions decrease every year from 0.622 tons per MWh avoided in 2012 to 0.518 tons per MWh avoided in 2030. This can be explained by what Hoogwijk et al. (2007) call "Declining quality of the resource in terms of power density and location, i.e. depletion of the wind resources" meaning that each next installation will be at a worse site than the previous site. Besides this, as Giebel (2000) points out, every next turbine replaces[3] production of a plant further down in the merit order, meaning that this plant will have lower fueld costs (and possibly CO_2 costs) than the one replaced before it.

[2] The term "net reduction" is used meaning that part of the reduction is offset by an increase of emissions from conventional power producers due to a decrease in emissions allowance prices.

[3] The word "replace" here can mean both "permanently replace a power plant" and "replace partially by substituting its production when wind is available."

The estimates of EWEA are based on the overall EU energy mix of coal, oil and gas. As will be seen in the next section, we are assuming that wind electricity would displace that produced from gas turbines, and since gas turbines produce less emissions than the mix of coal, oil and gas, our using CO_2 reduction estimates by EWEA can see as looking at the higher end of the spectrum. This is the approach we employ throughout this thesis as far as benefits are concerned.

As a default for optimistic and pessimistic scenarios, we assume a constant price of €15 per ton of CO_2. In the last 12 months the prices of allowances has been on a downwards trend and is currently traded at around €5 per ton of CO_2. We, therefore, do not follow most authors who write on this topic and assume a price of €25 per ton of CO_2.

3.2.3 Fuel Savings

Besides CO_2 emission reductions, one of the main benefits of renewable energy and wind power in particular is fuel-free generation. When the wind is blowing and turbines are running, this means they will replace – at least at those moments – conventional generators, and fuel will be saved. The amount of savings will vary from system to system (or country to country) depending on its electricity mix, or on what capacities will be displaced by wind generation. As mentioned in the quote in Section 3.1.3, wind power should potentially be used as base-load, i.e. as much as possible.

Since Germany has made a conscious effort to phase out nuclear capacities for ecology-conscious reasons, we assume that if it were not wind power, natural gas capacities would be used because natural gas produces considerably less emissions than coal (Moomaw, et al., 2011). Therefore, for the calculation of the fuel savings we assume that all electricity produced from wind would substitute that from natural gas. We use estimates of the European Commission (2010): 0.023 bn€/TWh in 2010, 0.0299 bn€/TWh in 2020, and 0.0388 bn€/TWh in 2030. The values for the intermediate years were calculated assuming a constant linear growth between the years.

3.2.4 Discussion of the Effect on the Price of Electricity

Nicolsi and Fürsch (2009) estimate long- and short-term effects of wind power on spot prices. They show that there is a much higher correlation between the load and spot prices than between wind power production and spot prices. This is similar to the previously-mentioned finding of Denny and O'Malley (2006) that decreasing the load is more efficient in decreasing CO_2 emissions than increasing wind power capacities. While they find that there is a price-decreasing effect in the short run, they also show that there will be an effect on the conventional capacities. The authors combine wind power in-feed and power prices with load and power prices and get a new parameter they call residual load, which is the demand that must be covered by the conventional power sources. In particular, the authors emphasize two situations: high load + low wind and low load + high wind, the first of which occurs statistically more often than the second and the two other possibilities (high load + high wind and low load + low wind). By plotting residual load and price, they show that for situations when the residual load is high (high load + low wind), the prices are abnormally high and low for situations when the residual load is low (low load + high wind). Both situations are unfavorable because in the first case, there is a scarcity in the market, and in the second, base load plants have to bid prices below their variable costs. The main advantage and economic reasoning behind using base load plants is in constant production, which minimizes their variable costs, but the situation when the residual load is low makes them bid negative prices. Otherwise, they would have to ramp down and then ramp up again, which means higher fuel and CO2 costs. As a result more peak load plants will be added to the mix instead of base load ones. These effects are correlated with wind power's generally low capacity credit, i.e. how much of the conventional power sources a power unit of installed wind capacities can substitute. In the end Nicolsi and Fürsch (2009) do not say that, on average, the prices would increase or decrease, but they do say that the price volatility will increase as more wind capacities are added into the system.

On the other hand Bode (2006) argues that since marginal costs of RES are lower than those of the conventional energy sources, the latter are driven out of the market as the production of renewable energy increases. Making an argument through the short-term demand-supply model, Bode states that with increasing penetration of wind power, the supply curve shifts to the right, and the wholesale prices, “which are part of the power costs of the consumers,” decrease. His study, as well as others (Pöyry, 2010) show that the elasticity of demand for electricity is quite low (0.015 in Bode’s paper); therefore, “minor changes in the supply can result in major price changes.” The author takes slope and intercept parameters for demand and supply curves from his previous research, and having performed a sensitivity analysis with different supply slope coefficients and remuneration sizes, he concludes that consumer prices may both increase and decrease.

While research by Bode (2006) does not give a definitive conclusion on the wind power’s in-feed on the electricity prices, Ketterer (2012) argues that they would decrease with rising wind-powered capacities. First specification of her GARCH (1,1) regression on day-ahead spot electricity prices provides that when the wind in-feed (in MWh a day) increases by 1%, the price decreases by 0.09-0.10%. The second specification states that when the wind’s share in the total electricity load rises by one percentage point, the price decreases by 1.32% to 1.46%. In both cases, nonetheless, the results also suggest that variance of prices increases with increased wind in-feed, an outcome observed by Nicolsi and Fürsch (2009) as well. It is worth noting that the increased variability can be considered covered in our calculation by our inclusion of back-up capacities and spinning reserve into the cost side of the calculation.

We follow Ketterer’s (2012) second specification and apply her outcomes in our calculations, however, not linearly. In her work, the author states that “the coefficient for the wind share in the mean equation… becomes less negative over time. The wind in-feed can no longer decrease the price level as much.” This effect is illustrated in Figure 3.1. Ketterer comments that the weakening of the merit-order effect can be explained by the growth of solar PV’s share in the overall production and stronger electricity trade in Europe (meaning wider possibilities to trade excess generation).

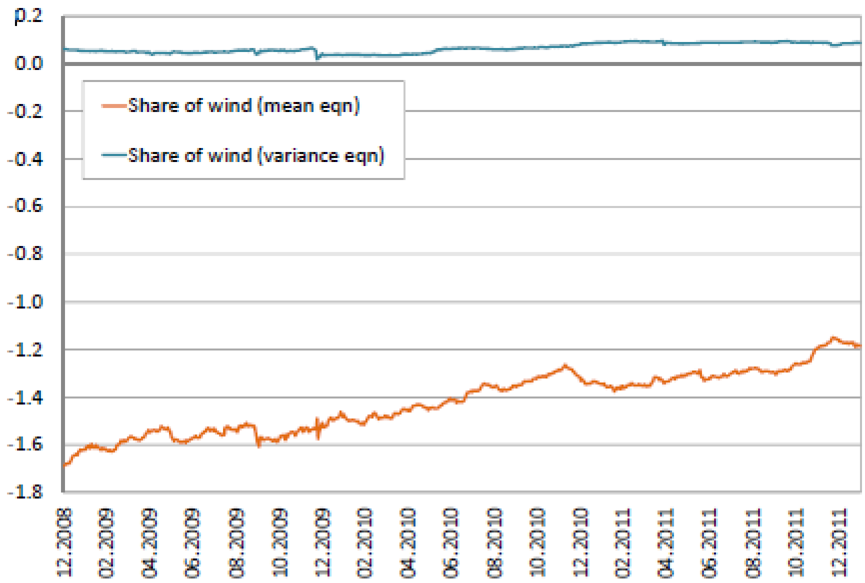


Figure 3.1: Rolling Regressions for the Variance and Mean Price Coefficients with 3-year Windows

Source: Ketterer (2012)

Looking at the graph above, we observe that the effect weakens on average by 0.1 percentage points every year. We extrapolate this effect starting from 2009 where the price decrease would have been 1.5% for the increase in the share of wind by 1 percentage point.

To justify our choice to use Ketterer's findings among others, we would like to present the concept of the merit order curve. This as a supply curve, which orders technologies by their marginal variable costs, so that each part of it represents one technology. This way, down at the beginning of the curve lie renewable technologies like wind and solar, then comes lignite and coal, followed by gas and ending with oil. Length of the segment would represent the technology's share (capacity) in the system. Figure 3.2 shows how the merit order curve would shift upwards if nuclear capacities were removed from the system. The increase of wind capacities, on the other hand, would shift the curve to the right, decreasing the price. This effect is illustrated in Figure 3.3.

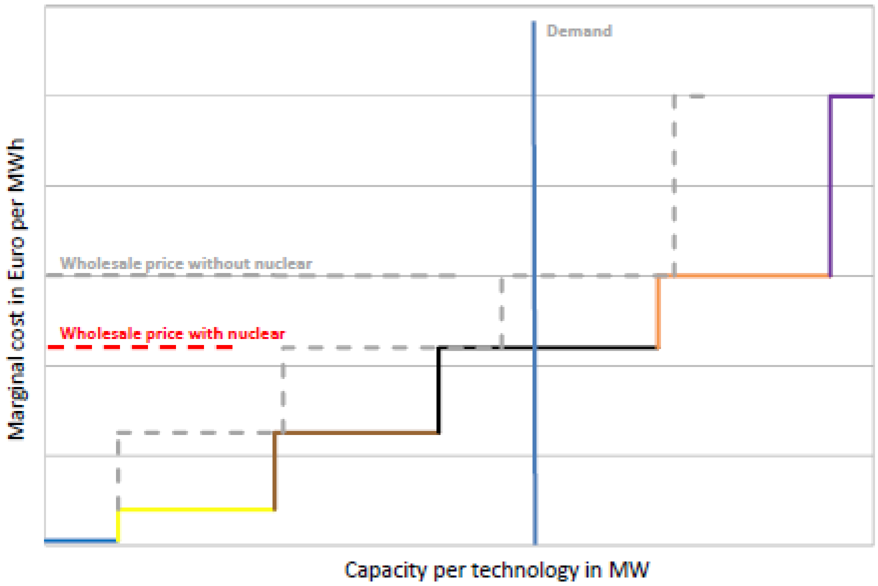


Figure 3.2: Shift of the Merit Order Curve after the Nuclear Phase-out

Source: Ketterer (2012)

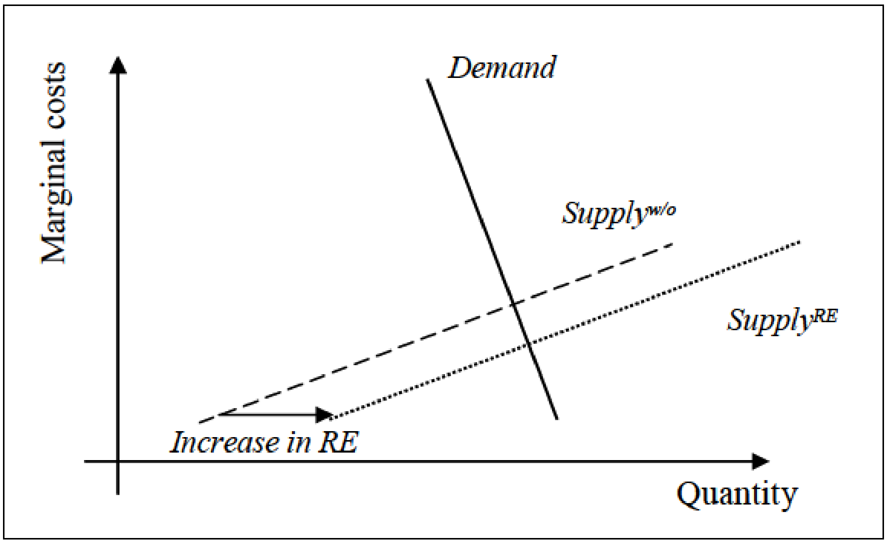


Figure 3.3: Shift of the Merit Order Curve due to Increasing Share of RES

Source: Bode (2006)

4 The Two Scenarios

The data on the installed capacity exists from the beginning of wind power development in Germany, which is 1990, and up till 2011. In the scope of this thesis, all the projection were made up to 2030, as this is when, we assume, all the support will end. The investment costs will go down enough for the wind power producers to sell their electricity without the support of the state. This will also happen due to the improvements in the turbine technologies, including increases in rotor diameter and hub height, which lead to increases in nominal capacity; so, wind turbines will get more and more efficient, needless to say more and more capable to capturing energy from both very weak and strong winds and transforming them into electricity.

The capacity projections for 2012-2020 were taken from the German National Renewable Action Plan. These, of course, include both onshore and offshore capacities. As can be seen in Table 4.1, the growth of around 14,000 MW is to a larger extent due to the expected extensive deployment of offshore capacities.

The projections from 2021 to 2030 take form of two scenarios: the optimistic one and the pessimistic one. Each scenario is governed by a set of assumption which apply to both of them and unique assumptions differentiating them one from another. The decision to have to scenarios was guided by the uncertainties which are always present in such long-term predictions, especially since no econometric model is used for future projections. Therefore, to make the results more credible, they will be presented in the form of a range rather than single numbers.

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total (MW)	31,357	32,973	34,802	36,647	38,470	40,154	41,909	43,751	45,750
Onshore (MW)	2,035	1,510	1,738	1,960	2,600	2,740	2,882	3,050	3,728
Offshore (MW)	89	131	192	279	399	561	758	981	1,219
New Onshore (MW)	792	1,302	2,040	3,000	4,100	5,340	6,722	8,272	10,000
New Offshore (MW)	2,035	1,510	1,738	1,960	2,600	2,740	2,882	3,050	3,728

Table 4.1: Projections of Wind Power Capacities until 2020

4.1 Assumptions Governing Both Scenarios

1) The average useful life of a wind turbine is usually assumed to be around 20 years. We will follow Liberman (2003) and assume a triangular distribution of a wind turbine's useful life with the minimum of 15, mode of 22.5, and maximum of 30 years. The probability density function is presented in Figure 4.1 and defined in Equation (4.1)
2) For simplicity's sake, we assume that no offshore wind turbines will be decommissioned by 2030. Since the expected life of a modern offshore wind turbine is expected to be 25 years, and by 2014 only 2040 MW of offshore capacities are projected to be installed, the inaccuracy would not be very high.

$$D = \begin{cases} 0 & for\ n < a \\ \dfrac{2(n-a)}{(b-a)(c-a)} & for\ a \leq n \leq c \\ \dfrac{2(b-n)}{(b-a)(b-c)} & for\ c < n \leq b \\ 0 & for\ b < n \end{cases} \tag{4.1}$$

where D is a decommissioning function, n is a number of years after commissioning of a wind turbine, a is the minimum expected lifetime, b is the maximum expected lifetime and c is the mode of life expectancy.

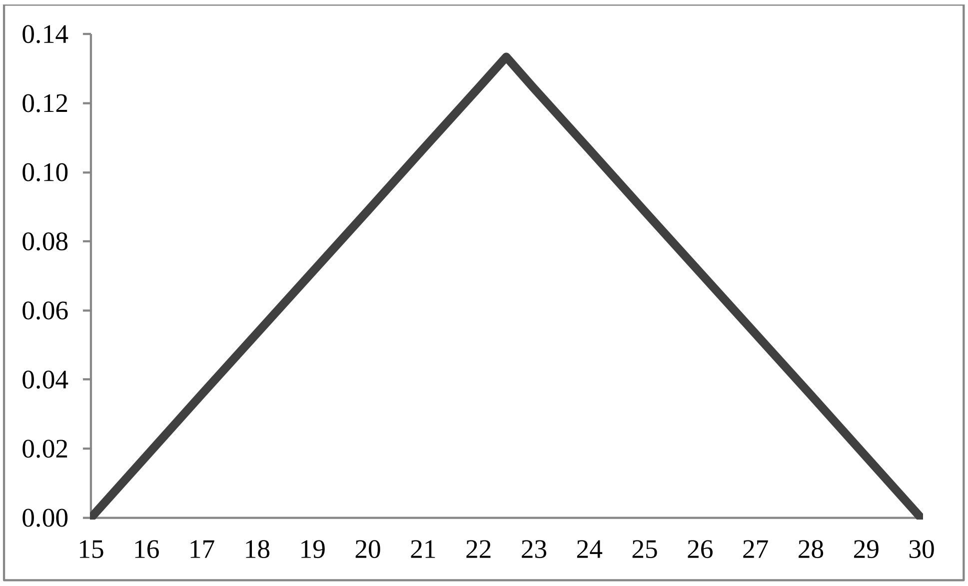


Figure 4.1: Assumed Probability Density Function of a Wind Turbine's Useful Life

4.2 The Optimistic Scenario

The optimistic scenario is designed to reflect a situation where the feed-in tariffs are not going to end soon, and/or a situation where the costs of technology decreases in correspondence to the decrease of feed-in tariffs, so that investors are ready to build new capacities.

Under the optimistic scenario the following assumptions are used:

1) The new capacities installed each year are 1.2 times the capacities decommissioned that year. For example, if in 2015, 1,000 MW of onshore capacities where decommissioned, then 1,200 MW of new onshore capacities would be installed.
2) The offshore capacities will reach 25,000 MW in 2030 which is the upper bound of the German government's estimate (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of Germany, 2002).

The projection of the onshore capacities takes the form of the simple formula below:

$$P_t = P_{t-1} - D_t + N_t \tag{4.2}$$

where P_t is the total onshore capacity in the year t, P_{t-1} is the total onshore capacity in the year $t-1$, D_t is the decommissioned capacity in the year t, and N_t is the new installed capacity in the year t.

The results of the optimistic scenario are over 64,000 MW of total installed wind capacity in 2030, out of which almost 40,000 MW are the onshore capacities and the rest, 25,000 MW are the offshore capacities. This result is consistent with the estimate provided by the European Commission (2010) in their Baseline Scenario. The detailed breakdown by year including new and decommissioned capacities is presented in Table 4.2.

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total (MW)	48,232	50,567	52,767	54,835	56,771	58,576	60,256	61,815	63,256	64,584
Onshore (MW)	36,043	36,381	36,758	37,164	37,582	38,003	38,420	38,827	39,216	39,584
Offshore (MW)	12,189	14,186	16,009	17,671	19,189	20,573	21,836	22,989	24,040	25,000
Total New (MW)	3,946	4,027	4,087	4,094	4,028	3,910	3,765	3,592	3,386	3,170
Decom. Onshore (MW)	1,464	1,691	1,887	2,026	2,092	2,105	2,085	2,033	1,945	1,842
New Onshore (MW)	1,757	2,030	2,264	2,431	2,511	2,526	2,502	2,440	2,334	2,210
New Offshore (MW)	2,189	1,997	1,822	1,663	1,517	1,384	1,263	1,153	1,052	960

Table 4.2: Projected 2021-2030 Capacities under the Optimistic Scenario

4.3 The Pessimistic Scenario

The pessimistic scenario is designed to reflect a situation where, firstly, the offshore capacity deployment will not go smoothly enough and secondly, the onshore capacities will not increase as much due the investor’s interest in either offshore wind farms or other types of renewables, where feed-in tariffs would be set up for precisely in accordance to the investment and maintenance costs.

Under the pessimistic scenario the following assumptions are used:

1) The new capacities installed each year are 1.0 times the capacities decommissioned that year. For example, if in 2015, 1,000 MW of onshore capacities where decommissioned, then 1,000 MW of new onshore capacities would be installed. Therefore, the onshore capacities are projected to stay flat over the period if 2021-2030.
2) The offshore capacities will reach 22,000 MW in 2030 which 2,000 MW higher than the lower bound of the German government’s estimate (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of Germany, 2002). This result means that in in the 20’s a little more capacities will be

commissioned than in the previous decade, which should reflect the progress in the technology of installing wind turbines in the sea, a process hard enough to be called compared by Fritz Vahrenholt, head of RWE's renewable energy division, with “the first expedition to the moon” (Dohmen & Jung, 2011).

The result of the pessimistic scenario is almost 58,000 MW of total capacities installed, out of which almost 36,000 MW would be onshore capacities. The detailed breakdown by year including new and decommissioned capacities is presented in Table 4.3.

Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total (MW)	47,536	49,078	50,502	51,819	53,036	54,160	55,200	56,160	57,048	57,868
Onshore (MW)	35,868	35,868	35,868	35,868	35,868	35,868	35,868	35,868	35,868	35,868
Offshore (MW)	11,668	13,210	14,634	15,951	17,168	18,292	19,331	20,292	21,180	22,000
Total New (MW)	3,132	3,233	3,312	3,342	3,309	3,230	3,124	2,994	2,833	2,662
Decom. Onshore (MW)	1,464	1,691	1,887	2,026	2,092	2,105	2,085	2,033	1,945	1,842
New Onshore (MW)	1,464	1,691	1,887	2,026	2,092	2,105	2,085	2,033	1,945	1,842
New Offshore (MW)	1,668	1,542	1,425	1,317	1,217	1,125	1,039	960	888	820

Table 4.3: Projected 2021-2030 Capacities under the Pessimistic Scenario

5 Calculating the Amount of Support

This chapter provides the summary of inputs needed for the calculation of feed-in tariff amounts for all years in this study and describes the methods used. The main inputs are:

- electricity produced each year (Section 5.2)
    - capacity factors of wind turbines are used to calculate this component (Section 5.1)
- amount of support per kWh (or other unit of energy) (Sections 5.3 and 0)
- number of years of the initial high tariff (Section 5.5)

In order to calculate the cost of government support for the wind power, one needs to know how much electricity will be produced in a given year and multiply that by the appropriate feed-in-tariffs. Since each year the electricity will be produced from installations commissioned in different years, a specific tariff will have to be applied to each of them. The third input (number of years of the initial high tariff) is the most sensitive since it determines for how many years out of 20 German producers would receive the increased initial tariff, which is guaranteed for the first 5 years for the onshore producers and 12 years for the offshore producers. Since the initial tariff is around two times higher than the basic tariff for the onshore installations and almost four times higher for the offshore installations.

It is true that the capacity installed for the whole year was not in operation for the whole year, so our electricity production calculations are not entirely correct. On the other hand, we are also not applying the EEG rule of paying out the tariff for the remainder of the year in which the installation was put connected to the grid plus for the next twenty years. In contrast we simply apply the tariff for twenty years. Therefore, if anything, the costs would increase if we had used some distribution of installation commissioning by the month.

5.1 Capacity Factor

Capacity factor is defined as the amount of electricity the wind turbine actually produces during a year divided by its nameplate capacity. Nameplate capacity, also known as nominal capacity, is the maximum power that a turbine can produce, which happens under favorable wind conditions. For example, for *Enercon E-82 2.0* (the *2.0* at the end suggests that the nameplate capacity is 2.0 MW or 2000 kW) such conditions start when the wind is blowing at 13 m/s and up till 25 m/s when the turbine will be shut or slowed down (such speed is known as the *cut-out speed*) to prevent damage to the turbine. For *Siemens SWT-2.3 93*, the nameplate capacity is 2300 kW. Such power output is reached at 14 m/s and stops also 25 m/s. A more formal representation of the capacity factor is shown below:

$$CF = \frac{MWh}{8760MW} \tag{5.1}$$

where MWh is the amount of electricity produced by a particular turbine in a year's time and MW is the nameplate capacity of the turbine. The nameplate capacity is multiplied by 8760, which is the number of hours in a year; the product, therefore, is the theoretical maximum amount of energy that the particular turbine could produce. If the *Enercon E-82 2.0* turbine worked the full 8760 hours of a given year at 2000 kW, it would produce 17520 MWh of energy, and its capacity factor would 1.0 or 100%.

It should be understood that capacity factor is not exactly a measure of a wind turbine's efficiency since it very much depends on the availability of wind. For example, the same wind turbine would have very different capacity factor if it were installed in the area where the mode of wind speed is 4 m/s and in the area where it is 7 m/s. On the hand, wind turbines have evolved very much in the last 25 years – and that is the main reason why in our thesis we expect the capacity factor to grow in time – and it is due to the changing characteristics and new technologies that different turbines can perform differently in the area, so wind turbines can capture more and more energy. Besides that, very often wind turbines are designed for specific types of location: high, medium or low wind. This promotional message in the *Siemens SWT-2.3 113* booklet explains how a new technology increases wind turbine efficiency: "The new Siemens SWT-2.3-

113 wind turbine is the ultimate choice for low to moderate wind conditions. The revolutionary direct drive generator and the new, optimized Quantum Blade are paired to extract as much energy as possible from the wind” (Siemens AG, 2011).

5.1.1 Approach to Calculation

Capacity factor is an important component of our calculation. It is needed to calculate both projected and past electricity production since neither of these is readily available. To be maximally clear, we do not know exactly how much electricity was produced by the turbines commissioned in any particular year (such turbines will be referred to as “new turbines”). Only aggregate numbers for each year are available: this means including electricity produced by both old (commissioned in the past) and new turbines (commissioned at the observed year).

In order to do that we calculated two types of capacity factors for each year: one included all capacities – old and new – which were functioning during a given year, another included only new capacities.

Before we commence into explaining how we calculate these different types of capacity factors, we should mention that calculations of capacity factors – and consequently all other variables – can be divided into two main periods: 1990-2020 and 2021-2030. The main distinction between the two periods is that in the first one installed capacities and produced electricity are used as inputs for calculation of capacity factors while in the second one they are outputs calculated from projected capacity factors. The summary of the approach used to calculations can be found in Table 5.1.

Period	Sub-period	Approach to Calculating General Capacity Factor	Approach to Calculating New Capacity Factor	Commentary
1990-2020	1990-2011	Calculated from produced electricity and installed capacity figures [Equation (5.2)]	Assumed to grow from 0.17 to 0.21	During this period electricity produced and capacities installed are used to calculated general capacity factor, from which new capacity factors are inferred.
	2012-2020		Calculated from the rate of growth of general capacity factors to which 0.01 is added.	
2021-2030	2021-2030	Irrelevant	Capacity factors grow with CAGR of 2012-2020 but decelerate by a rate, designed to flatten the growth curve by 2030, i.e. the growth of efficiency will stop.	During this period installed capacities and produced electricity are outputs rather than inputs. Installed capacities are calculated based on growth projections according to the optimistic and pessimistic scenarios, and produced electricity is calculated based on projected capacity factors.

Table 5.1: Summary of the Approach to Main Calculations

The first type of the capacity factor – the general capacity factor – is presented by the equation below:

$$CF_T = \frac{MWh_t}{8760(MW_T + 0.65MW_t - 0.5MW_{D,t})} \tag{5.2}$$

where CF_T is the general capacity factor for year t, MWh_t is energy produced in year t, MW_T is total capacities available before year t and $MW_{D,t}$ are capacities decommissioned in year t.

In the Equation (5.2) we are modifying Equation (5.1) by breaking the denominator into its component parts and multiplying each of them by factor, which would represent how much time they had a chance to be in operation. The 0.65 coefficient for new capacities is derived from the fact that most capacities in Germany are installed in the second half of the year and the 0.5 coefficient for decommissioned capacities is based on the assumption that capacities are evenly decommissioned throughout the year. These coefficients were introduced because we are focusing on that component of the capacity factor, which represents turbine efficiency.

Unlike the general capacity factor, new capacity factor is calculated differently for the two sub-periods of 1990-2020. For 1990-2011 we will employ a constant capacity factor; the reason for this will be explained in section 5.1.2. For 2012-2020 we use the following Equation:

$$CF_t = CF_{t-1}\left(\frac{CF_T}{CF_{T-1}}\right) + 0.01 \tag{5.3}$$

Where CF_{t-1} is the new capacity factor from year $t-1$, CF_T is the general capacity factor in year t, and CF_{T-1} is the general capacity factor in year $t-1$.[4]

Let us now move to the second major period in our calculation, which is 2021-2030. This is a period for which no projections were taken from external sources; therefore, all projections were made by us, and the first step was the projection of capacity factors. The following method was used:

$$CF_t = CF_{t-1}[1 + CAGR_{2012.2020} - C(t-2020)] \tag{5.4}$$

where CF_t is the new capacity factor for year t, CF_{t-1} is the new capacity factor from year $t-1$, $CAGR_{2012.2020}$ is compound annual growth rate of the new capacity factor for the years 2012-2020, and C is a constant, designed to flatten the growth curve by 2030.

The equation above needs to be used only for the calculation of the new capacity factor since it is this type of capacity factor that we need to calculate the energy produced by the new turbines. The new capacity factor is no longer inferred from the general capacity factor; therefore, the latter is not needed to be calculated for the years 2021-2030.

As becomes evident from Equation (5.4) the capacity factor is projected to keep growing in the future but with decreasing velocity every year. This is achieved by

[4] To distinguish the new capacity factor from the general one, we used small and capital letter t.

introducing the constant C, which is different for the onshore and offshore CFs, but which will by 2030 flatten the curve of CF growth.

5.1.2 Results of the Calculation and Usage

We used the figures on the energy produced and capacities installed from 1990 to 2020 to obtain the capacity factors. The data from 1990 to 2012, of course, is historical while the data from 2013 to 2020 are projections made by the German government in the National Renewable Energy Action Plan (Federal Republic of Germany, 2010).

Having used Equation (5.2) for year 1990 through 2011 we have obtained the average capacity factor of 18.05%, which is consistent with Boccard (2009), which estimated the capacity factor in Germany during years 2003-2007 at 18.3%.

We assume that new turbines will have higher capacity factor; therefore, for years 1990 to 2011, capacity factor for new turbines was assumed to be on average 19.55% growing from 0.17 to 0.21. Such assumption is made since there is no other reliable way to estimate this parameter precisely without very accurate data.

In the above-mentioned sub-period offshore turbines were not discussed since they were simply absent. However, beginning with 2012, offshore wind turbines are expected to be installed on a large scale in Germany; therefore, calculations will include offshore wind turbines data.

The calculated capacity factors can be found in Appendix A, Table A.1 and Table A.2.

5.2 Calculation of the Electricity Produced

After the projections of installed capacities and capacity factors, we can calculate the electricity produced. Due to the specificity of the German support scheme, we are interested in how much electricity is produced by the new turbines in each year, just like with capacity factors. Calculation for the electricity produced is fairly simple:

$$E_t = MW_t CF_t \tag{5.5}$$

where E_t is electricity produced in year t and CF_t is the new capacity factor for year t.

Equation (5.9) is used both for onshore and offshore installations, with their respective capacities and capacity factors. Installed capacities differ for the Optimistic and Pessimistic scenarios, but capacity factors remain the same.

Results of the calculation are presented in Appendix A, Table A.3.

5.3 Assumptions on the feed-in tariffs

Feed-in tariffs are the second important component of our calculation. The actual historical numbers for the years 2000-2012 were taken from “Act on Granting Priority to Renewable Energy Sources” as of years 2000, 2004, 2009, and 2012. Remuneration schemes prior to 2000 do not matter since the new EEG legislature (the original year 2000 edition) treats all capacities commissioned prior to 2000 as commissioned on January 1, 2000; therefore, the newly implemented feed-in tariffs could be used in the calculation of the support for all the installations previously installed.

For future, we assume that tariffs will digress with the rates specified in the latest edition of the EEG, year 2012. For onshore installations this would mean a digression of 1.5% for both the initial and basic tariff. Offshore installations will enjoy 0% digression for the years 2012-2017, after which it will be 7%.

We believe these assumptions are reasonable since after in the three revisions of the EEG the tariffs were raised only once, in 2009. The digression rates for onshore installations stayed in the range of 1-2% during 2000-2011. The current rate of 1.5% is justified by the expected continuous decrease of the investment costs in line with that rate. Offshore investment costs are expected to decrease with an average rate of 3.11% while the tariffs will decrease with the average rate of 5.11%.

Correlations between investment costs and feed-in tariffs are displayed in Figure 5.1 and Figure 5.2. For onshore installations the graph was built beginning with 2012 because this is when the tariffs where last reviewed in the EEG and after which point they gradually decrease. For offshore 2018 was used as a starting point because until that year both initial and basic tariffs are fixed, and there would be certainly no correlation visible.

We also assume that all onshore installations will comply with the technical specifications required by the EEG and receive the so-called "system services bonus," which is also subject to the digression of 1.5%.

Specific tariffs used for each year are presented in Appendix A, Table A.6

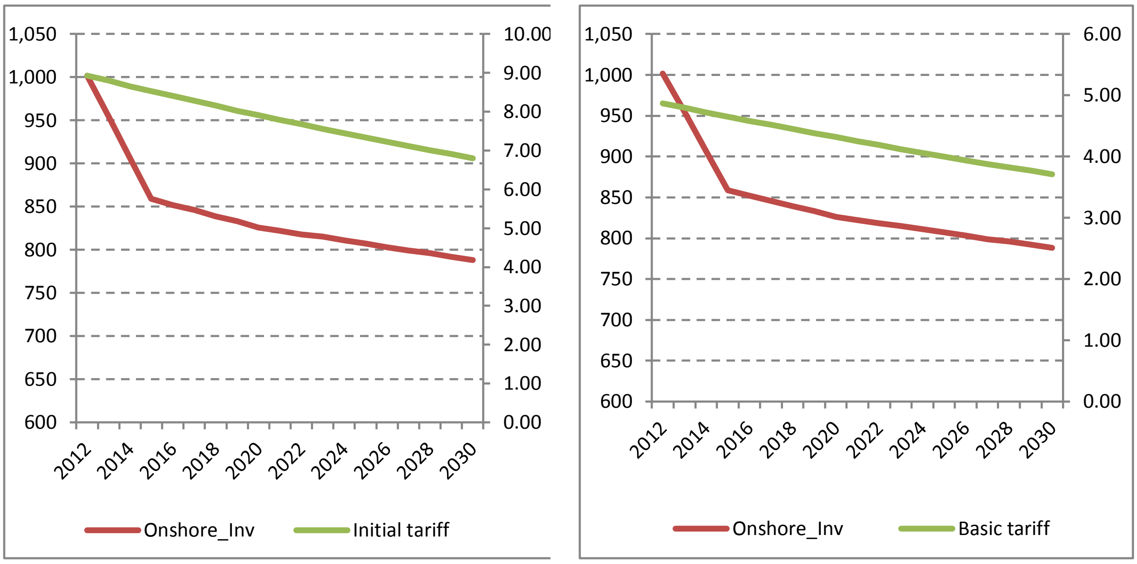


Figure 5.1: Correlation between Investment Costs and Tariffs for Onshore Installations

Source: author's representation of European Wind Energy Association (2009)

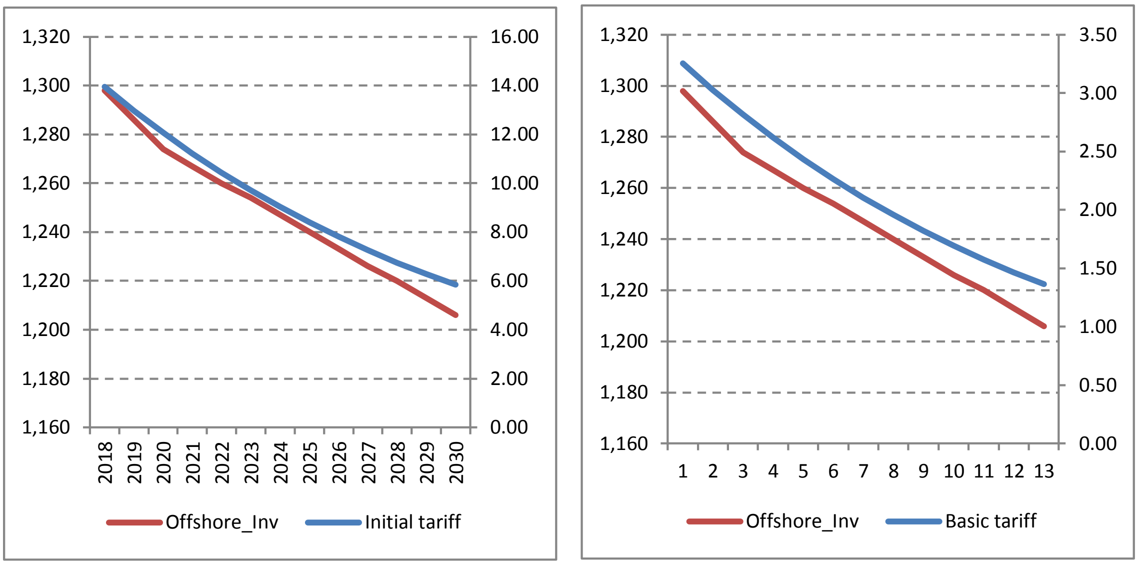


Figure 5.2: Correlation between Investment Costs and Tariffs for Offshore Installations

Source: author's representation of European Wind Energy Association (2009)

5.4 Calculation of the Support

For our study we are specifically interested in the electricity produced by new turbines due to the nature of the support system in Germany: the tariff during the lifetime of the turbine depends on the year in which it was commissioned as explained in Section 2.3. Consequently, having found a production figure for the installations commissioned in a particular year, this number is then used for 20 years ahead to calculate the support needed by multiplying this produced electricity by the appropriate feed-in tariff and decreasing it by taking into account the expected decommissioning as described in section 4.1, point 2. For a given year, the support for wind turbines commissioned in a given year will be calculated in the following way:

$$S_n = E_t T_t D_n \tag{5.6}$$

where S_n is the support expressed in euros n years after commissioning of the turbine, E_t is the amount of electricity produced by the turbines, which were commissioned in year t, T_t is the tariff applied to installations commissioned in year t, and D_n is the decommissioning factor – the cumulative distribution function of d_n specified in (4.1).

5.5 Extension of the Initial Tariff

In the previous section we have specified the formula for the calculation of support, which included the tariff specific for a particular year. However, as has been explained in Chapter 2.3, for each year there exists the higher initial tariff and the basic tariff. It has also been stated that the initial tariff is provided for a minimum of 5 years in case of onshore turbines and 12 years in case of offshore turbines, both of which can be extended in accordance with the rules described in Chapter 2.3. The rest of this chapter describes the methodology which was used to estimate this very important parameter.

5.5.1 Onshore Installations

In the case of onshore installations, the extension of the initial tariff essentially depends on the quality of the installation site, that is the steadiness and mean velocity of wind. This site is then compared to the reference site specified in the EEG in terms of how much power a given turbine would produce at the installation site as compared to the reference site. Let us quote the law once again: the initial tariff will be prolonged “by two months for each 0.75 per cent of the reference yield by which the yield of the installation falls short of 150 per cent of the reference yield,” or by one year for each 4.5%. For example, if at the standard site a turbine produced 4000 MWh in one year and at the site of interest 5000 MWh (due to better wind conditions), it would produce 125% of the reference yield and the initial tariff would be prolonged by (150%-125%)/4.5% = 5.56 years. Therefore this turbine would receive the initial tariff for a little over 10.5 years and basic tariff for the rest, almost 9.5 years.

What we are aiming to do is to estimate such a number for Germany in general. To do this we will use Weibull distribution of wind speeds in all states of Germany and power curves of a few turbines.

5.5.1.1 Weibull Distribution

Wind speeds around the world have been found to follow the Weibull distribution. The Weibull distribution’s probability density function is given below:

$$p(x) = \frac{k}{\lambda}\left(\frac{x}{\lambda}\right)^{k-1} e^{-\left(\frac{x}{\lambda}\right)^k} \tag{5.7}$$

where k is the shape parameter and λ is the scale parameter of the distribution.

The shape parameter reflects variability of the wind and usually takes values between 1 and 3. The higher the value the steadier are the winds at the location. The scale parameter reflects the mean speed at the location and has a value slightly higher than the mean speed. The mean of the Weibull distribution is given by

$$\bar{x} = \lambda\Gamma\left(1 + \frac{1}{k}\right)$$

where $\bar{x}$ is mean wind speed, λ is the scale parameter, Γ is the gamma function, and k is the shape parameter.

From this it follows that the scale parameter is:

$$\lambda = \frac{\bar{x}}{\Gamma\left(1 + \frac{1}{k}\right)} \tag{5.8}$$

Before we move forward it is necessary to review and discuss the characteristics of the reference site.

5.5.1.2 The Reference Site and Logarithmic Wind Profile

Let us once again list the parameters of the reference site as found in the EEG:

1) Mean wind speed of 5.5 m/s at the height of 30 m
2) Rayleigh distribution of wind
3) Logarithmic wind profile with roughness height of 0.1 m

Let us comment on these parameters. First of all, Rayleigh distribution of wind means the Weibull distribution with *k=2.* Second, by having the mean speed one can calculate the scale factor as defined in Equation (5.8). Third, logarithmic wind profile means that wind speeds at the given site follow the following law:

$$\frac{x(z)}{x(z_r)} = \frac{\ln(z/z_0)}{\ln(z_r/z_0)} \tag{5.9}$$

where $x(z_r)$ is wind speed at the height z_r, $x(z)$ is wind speed at height z, z_0 is roughness height.

Roughness height is a characteristic of terrain "density." For example territories with low grass or airports would have the roughness height of 0.03 m while terrains with tall row crops of low woods would have the roughness height of 0.25 m. Reference site has the roughness height of 0.1, which means "land, high grass, low crops" (Jongh & Rijs, 2004).

All three characteristics will be used further in our estimations.

5.5.1.3 The Power Curves

A power curve is a wind turbine's output plotted for different wind speeds, usually from 0 to 25 m/s, with air density of 1.225 kg/m^3. Most wind turbines start producing electricity around 3-4 m/s and cut-off to protect the turbine around 25 m/s. For this study we will use power curves of three turbines to estimate their average outputs at various places in Germany and compare them to the outputs they would have at the reference site. We use five modern wind turbines for "safer" results because each one has a different power curve and will perform better or worse given the site's distribution of wind.

The wind turbines used are Enercon E-82 2.0, Enercon E-70 2.3 and Siemens SWT-2.3 93, Vestas V-90 3.0, and Vestas E-101, all of which are modern wind turbines with nominal capacity of 2 megawatts or more. Vestas and Enercon turbines represented more than 80% of all installed turbines in Germany in 2011 (Molly, 2012). Siemens' turbine was included for influence on the results because of its possible better fit for certain territories. The power curves of the five turbines used are presented in Figure 5.3.

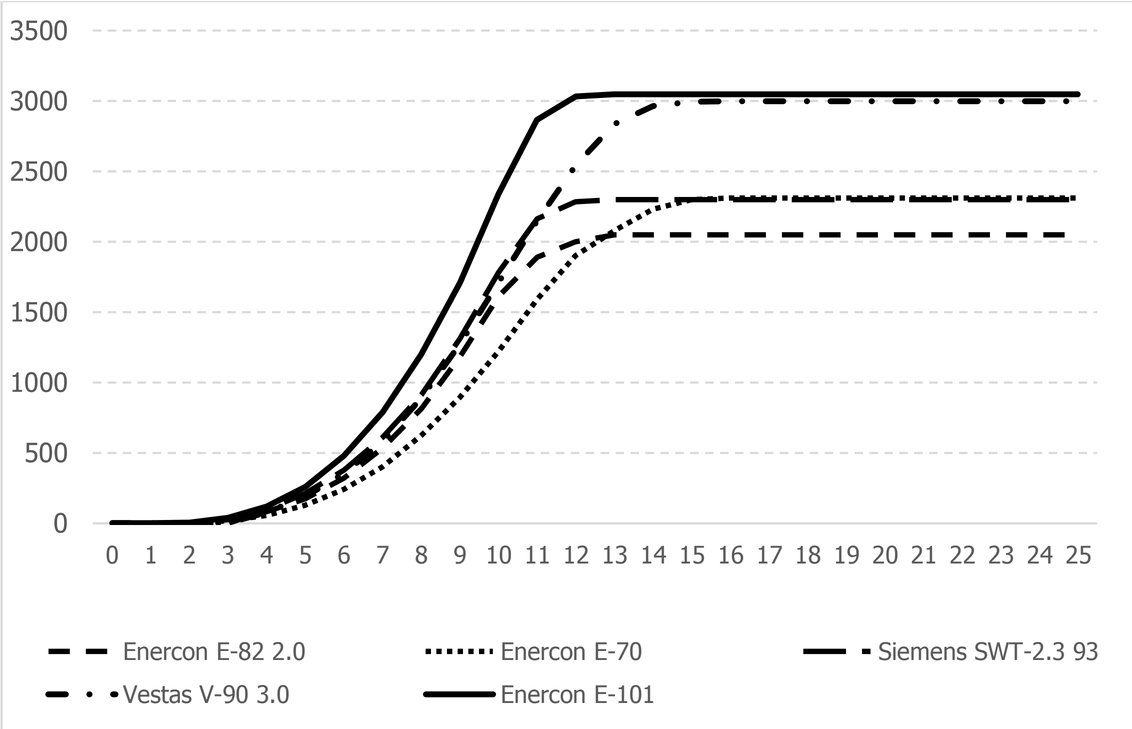
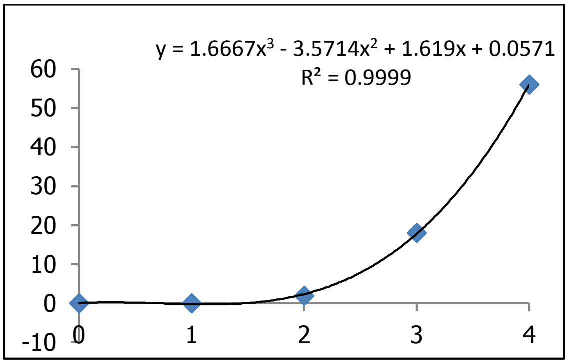


Figure 5.3: Combined Power Curves

Source: author's illustration of manufacturers' data (ENERCON GmbH, 2012; Vestas Wind Systems A/S, 2012; Idaho National Laboritory, n.d.)

5.5.1.4 Fitting Power Curves

The power curves for all wind turbines were fitted by plotting them with MS Excel 2010/2013 using "X Y (Scatter)" chart type. For some turbines the curve was divided into two parts if it provided better fitting: 0-4 m/s and 4 to the wind speed at which the turbine reaches its nominal output, as used for Enercon E82, Enercon E-70, and Enercon E-101. For other turbines fitting started with the wind speed at which the turbine starts production and until it reaches its nominal capacity. An example of a fit power curve for Enercon E-70 2.3 is presented in Figure 5.4. The complete specification for all wind turbines can be found in Appendix B.



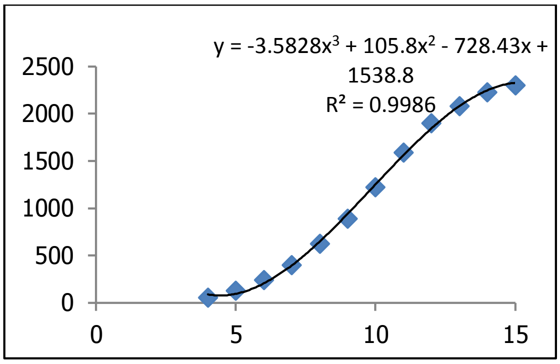


Figure 5.4: Fitted Power Curve in two Segments for Enercon E-70 2.3

5.5.1.5 Calculating Output

To calculate the output of a given wind turbine at a given site, we need the parameters of the Weibull distribution for that site and the fitted power curve for the given wind turbine. The probability density function of the specified Weibull distribution and the power curve are then multiplied and integrated to obtain the average output at the given site by the given turbine as specified in the Equation below:

$$E(x) = \int_{0}^{25} p(x)W(x)dx \tag{5.10}$$

where $p(x)$ is probability distribution function of mean wind speed at the given site and $W(x)$ is the power curve of the given turbine.

The integration was done in MS Excel 2010/2013 using the trapezoid method, specifically:

$$E(x) = \Delta x \sum_{x=0}^{25} \frac{p(x) + p(x+1)}{2} \cdot \frac{W(x) + W(x+1)}{2} \tag{5.11}$$

5.5.1.6 Calculating the Years of Initial Tariff

We have been able to obtain daily mean wind speeds from 60 weather stations in Germany, which were available for free at the WebWerdis database of the Ministry of

Transport, Building and Urban Affairs. This data was used to estimate the shape and scale parameters for different states in Germany by means of Maximum-likelihood Weibull Distribution Fitting online tool (Wessa, 2013). Unfortunately, the number of stations was not enough to cover the territory of Germany sufficiently and get representative results. Nevertheless, the results of fitting were used to get an idea about the shape parameters at different parts of Germany. The scale parameters were obtained from mean wind speeds at different parts of Germany. Mean wind speeds were obtained from detailed state-by-state maps provided by the Ministry of Transport, Building and Urban Affairs (Deutscher Wetterdienst, 2013). An example of such a map can be found in Appendix C, Figure C.1.

At each state's map zones of certain wind speed concentrations were identified. For each zone like this the Weibull scale parameter was calculated using Equation (5.8). Knowing the scale and shape parameters, we constructed the Weibull distribution for each wind zone like this. Having this information, we calculated the output of each of the five wind turbines for every zone (Equation (5.11). Before this, we calculated the output of each of the five turbines at the reference site. To calculate the number of years of initial high tariff at any zone we use the following logic:

$$N_Z = 5 + \frac{min\left(1.5E_{R,i} - E_{Z,i}, 1.5E_{R,i+1} - E_{Z,i+1}, \ldots, 1.5E_{R,n} - E_{Z,n}\right)}{0.045} \quad (5.12)$$

where N_Z is the number of years of initial tariff at zone Z, $E_{R,i}$ is the average output of the turbine i at the reference site, and $E_{Z,i}$ is the output of turbine i at the given zone.

Equation (5.12) takes care of the fact that some turbines might be suitable for one site more than for another as discussed in section 5.5.1.3. We therefore assume that the turbine which performs the best at a given zone will be installed there, which is reasonable.

Each zone was given weight according to the approximate installed capacity as share of total capacity of the state (or states, in cases where they were combined[5]). This number

[5] Lower Saxony was analyzed together with the city-states of Hamburg and Bremen, Brandenburg with the city-state of Berlin, Rhineland-Palantine with Saarland (the smaller states are enclosed by the larger ones), and Hesse together with Thuringia (because the original weather station analysis was combined)

was then multiplied by the state's share in the total installed capacity in Germany as of 2011 (Molly, 2012). In the end the calculation for the weighted average number of years of the initial tariff comes down to the Equation below:

$$\bar{N} = \sum_{S} \sum_{Z} N_Z W_Z W_S \tag{5.13}$$

where $\bar{N}$ is the weighted average number of years of initial tariff across Germany, N_Z is the number of years of initial tariff at zone Z, W_Z is weight of zone Z, W_S is the weight of state S, to which zone Z belongs.

5.5.2 Offshore Installations

Extension of the initial tariff for offshore as described in section 2.3.2 is much simpler. The number of years of initial tariff simply depends on the remoteness of the installation from the seashore and depth at which it is installed.

To calculate the years of initial tariff for offshore installations, we used data about 25 operating and approved (to be built and commissioned in the future) wind farms (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, n.d.). The depths and distances for each farm where weighed with installed capacity; therefore, the final number of years was calculated as follows:

$$\bar{N} = 12 + \frac{0.5(\sum_i S_i W_i - 12) + 1.7(\sum_i D_i W_i - 20)}{12} \tag{5.14}$$

where $\bar{N}$ is the weighted average number of years of initial tariff for offshore installations, S_i is the distance of the installation i in nautical miles from the seashore, D_i is the depth of the installation i in meters, and W_i is the weight of the installation i.

5.5.3 Results of the Calculation

Having applied Equation (5.13) on our data, the number of years of initial higher tariff for onshore installations was estimated at **16.68 years** (meaning additional 11.68 years to the guaranteed 5). For offshore installations (Equation (5.14), the number of years is **14.42** (meaning additional 2.42 years to the guaranteed 12).

6 Results

This chapter presents the final amounts of costs and benefits after the assumptions of Chapters 3 and 4, and calculations of chapter 5 were integrated.

Since assume that the support will end in 2030, this means that the installation that is commissioned in 2029 will not a get a 20-year contract (as it has always been under the EEG), but only a 2-year one. One could imagine that at some point the German government will announce that the support (at least of the wind technology) will end in 2030. The investors, nevertheless, can still build turbines and receive the tariff for the years remaining until 2030.

We use two indicators for the level of final costs, one including the grid extension costs and the other excluding them. While the costs on grid extension are inevitable and a direct result of wind power expansion in Germany, the latter number (grid extension costs excluded) serves as a number representing the approximate cost of the technology itself without extraneous factors, an indicator useful by itself.

Section 6.1 presents the summary of assumptions and values of the components that were used for the calculation of costs and benefits. Section 6.2 presents the results for onshore installations. Section 6.3 presents the results for offshore installations. Section 6.4 presents the sensitivity analysis for onshore installations.

6.1 Summary of Components for Costs and Benefits

Before we present the results we would like to summarize the default assumptions on the side of costs and benefits:

6.1.1 Summary of Components for Costs

Feed-in tariffs: according to the 2000, 2004, 2009, and 2012 editions of the EEG law. Complete list of tariffs can be found in Appendix A, Table A.6.

Grid extension: €20 bn for onshore evenly spread from 2014 to 2023, €22 bn for offshore evenly spread from 2014 to 2023.

Additional costs: comprise the need for back-up reserve and cycling costs of the spinning reserve. These costs are expressed in bn€ per TWh and depend on the penetration of wind in the overall load. In our case they grow from €0.04875 bn per TWh at the penetration of 8.4% to €0.051375 bn per TWh at 26% penetration (pessimistic scenario) and to €0.0525 bn at 29.1% penetration (optimistic scenario).

6.1.2 Summary of Components for Benefits

Electricity produced and wholesale spot price: We take EEX wholesale spot price predictions by Traber, et al. (2011) for calculating this benefit entry. Using their ESSYMMETRY electricity market model they estimate that in 2020 the average inflation-adjusted wholesale electricity price in Germany will be €49.3 per MWh, which a 11% increase over the 2010 price. We extrapolate this increase from 2020 to 2030 and obtain a price of almost €55.

CO_2 emission reduction: avoidance drops year to year from 0.622 tons per MWh in 2012 to 0.518 tons per MWh in 2030. Price per ton of CO_2 is set at €15.

Fuel savings: we assume that in-feed from wind turbines will replace that of gas turbines. This assumption steps of perceived desire of Germany to reduce greenhouse gas emissions, which are lower for gas-fired capacities than coal, another major type of electricity production in Germany. Natural gas prices are 0.023 bn€/TWh in 2010, 0.0299 bn€/TWh in 2020, and 0.0388 bn€/TWh in 2030. The values for the intermediate years were calculated assuming a constant linear growth between the years.

Electricity wholesale price decrease: We use Ketterer's (2012) findings: by increase the share of wind in the electricity load by 1 percentage point, the electricity price would decrease by 1.32 to 1.46%. From the additional graph we found that the decrease in 2009 was on average 1.5% per increase of load by 1 percentage. The effect, however, lessens over time, approximately by 0.1 percentage point per year; we use this finding in our study.

6.2 Onshore

The analysis of costs and benefits for onshore installations in the default setting showed that under both pessimistic and optimistic scenarios the costs cumulatively (2012-2030) overweigh the benefits: by €49 bn and €52.69 bn respectively. Furthermore, under both scenarios the costs are greater than the benefits for any given year, with no visible convergence.

6.2.1 The Pessimistic Scenario

The results of estimated costs and benefits for the onshore installations under the pessimistic scenario are summarized in two tables below.

Feed-in Tariffs	105.64
Grid Extension	20.00
Additional Costs	68.53
Total without Grid Extension	***174.16***
Total	**194.16**

Table 6.1: Summary of Costs under the Pessimistic Scenario (in €bn)

CO_2 Emission Reduction	11.82
Electricity Produced	70.32
Wholesale Price Decrease	19.30
Fuel Savings	43.72
Total	**145.16**

Table 6.2: Summary of Benefits under the Pessimistic Scenario (in €bn)

Taking a look at the tables above gives a clear idea that costs vastly overweigh the benefits in this specification. Even if grid extension costs were excluded from excluded from the calculation, the costs would still overweigh the benefits by €29 bn. Figure 6.1 also shows that the costs are higher than the benefits during all the years, with no visible trend for convergence.

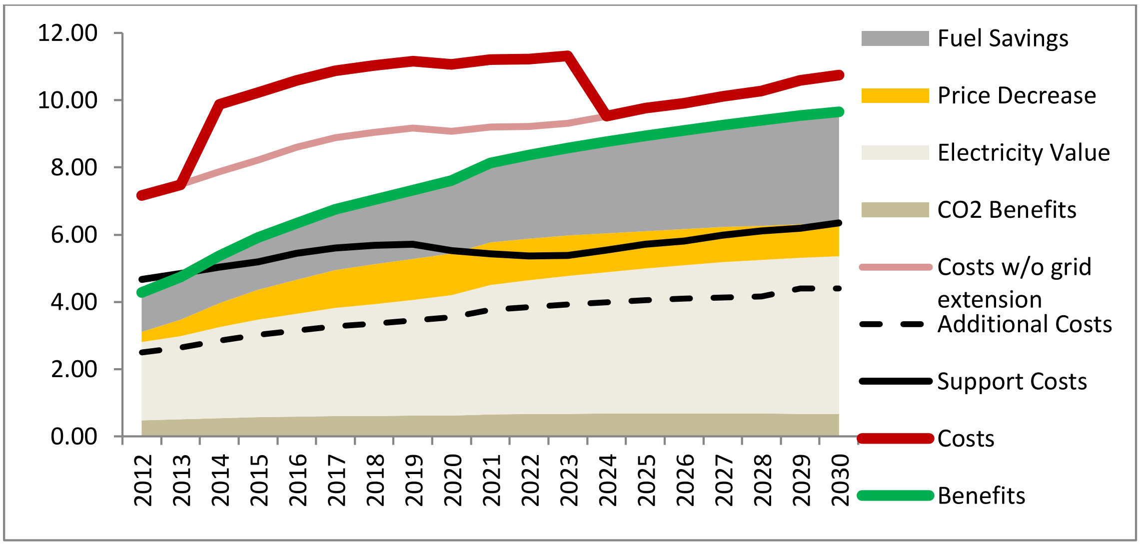


Figure 6.1: Summary of Costs and Benefits for Onshore Installations under the Pessimistic Scenario (in €bn)

6.2.2 The Optimistic Scenario

The results of estimated costs and benefits for the onshore installations under the optimistic scenario are summarized in two tables below. The costs again overweigh the benefits, in this specification, even more: the costs increased by €8.37 bn while the benefits increased by €7.10 bn.

Feed-in Tariffs	109.97
Grid Extension	20.00
Additional Costs	71.78
Total without Grid Extension	***181.75***
Total	**201.75**

Table 6.3: Summary of Costs under the Optimistic Scenario (in €bn)

CO_2 Emission Reduction	12.21
Electricity Produced	72.88
Wholesale Price Decrease	18.52
Fuel Savings	45.46
Total	**149.06**

Table 6.4: Summary of Benefits under the Optimistic Scenario (in €bn)

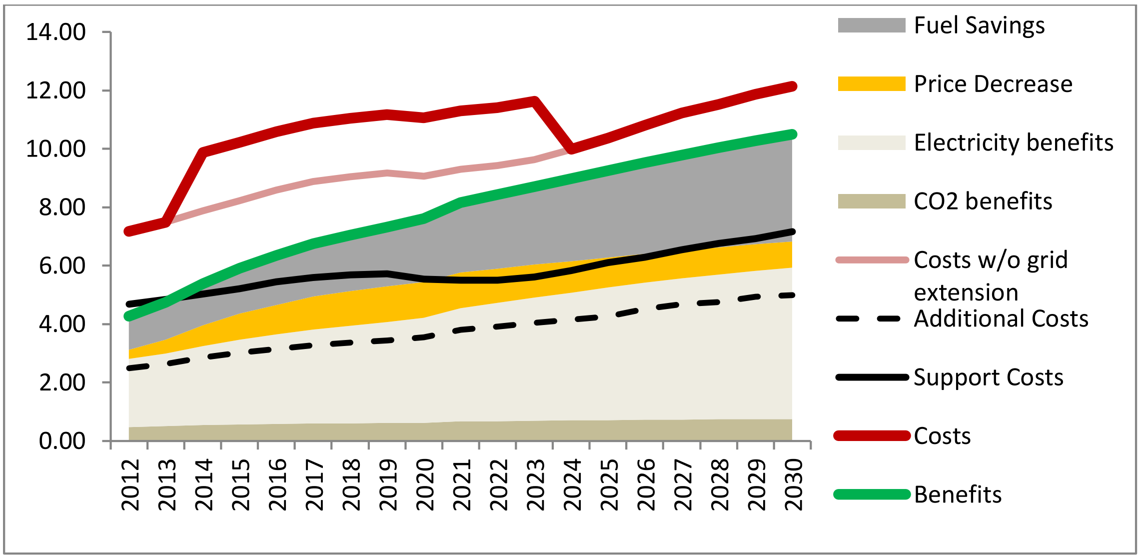


Figure 6.2: Summary of Costs and Benefits for Onshore Installations under the Optimistic Scenario

6.3 Offshore

This section presents the results on the analysis of costs and benefits for the offshore capacities. Under both optimistic and pessimistic scenarios the costs overweigh the benefits. There is, however, is a visible convergence, i.e. it could be assumed that the benefits could start overweighing the benefits in 2035 or so. The

6.3.1 The Pessimistic Scenario

Feed-in Tariffs	86.51
Grid Extension	22.00
Additional Costs	37.37
Total without Grid Extension	***123.88***
Total	**145.88**

Table 6.5: Summary of Costs under the Pessimistic Scenario (in €bn)

CO_2 Emission Reduction	6.22
Electricity Produced	39.94
Wholesale Price Decrease	10.09
Fuel Savings	25.74
Total	**81.39**

Table 6.6: Summary of Benefits under the Pessimistic Scenario (in €bn)

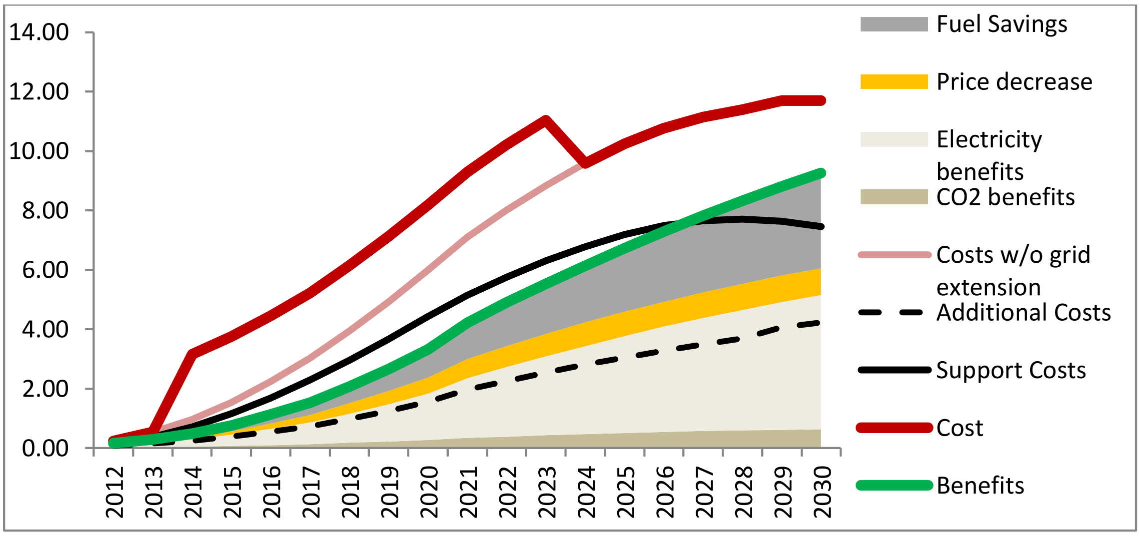


Figure 6.3: Summary of Costs and Benefits for Offshore Installations under the Pessimistic Scenario

6.3.2 The Optimistic Scenario

Feed-in Tariffs	94.04
Grid Extension	22.00
Additional Costs	38.21
Total without Grid Extension	***132.25***
Total	**154.25**

Table 6.7: Summary of Costs under the Pessimistic Scenario (in €bn)

CO_2 Emission Reduction	6.81
Electricity Produced	43.22
Wholesale Price Decrease	10.10
Fuel Savings	28.35
Total	**88.48**

Table 6.8: Summary of Benefits under the Pessimistic Scenario (in €bn)

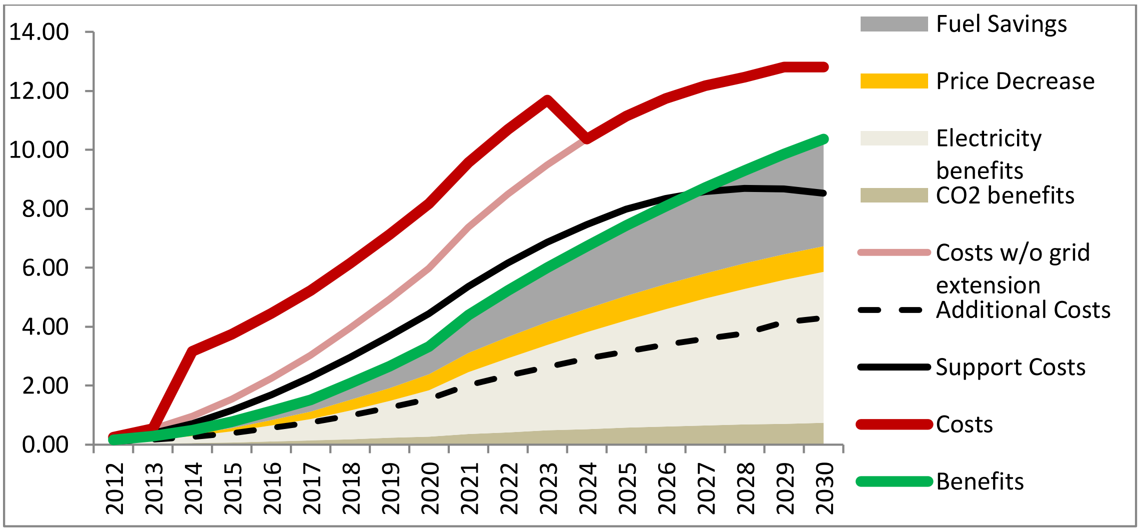


Figure 6.4: Summary of Costs and Benefits for Offshore Installations under the Optimistic Scenario

6.4 Sensitivity Analysis

In this section we present the results of five sensitivity analyses for onshore installations, which we have performed trying see how sensitive our results to changes in the components used. The sensitivity analyses were performed only for the onshore installations because for offshore the trend of benefits was suggesting that they would break even with costs around 2035. Onshore, on the other, did not look promising under the baseline scenario. The results are presented only for the pessimistic scenario since it has shown to provide higher net benefits both for the onshore and offshore installations. The five scenarios are:

1) **High CO_2 Price** scenario: CO_2 price of €25 per ton

2) **High Electricity Price** scenario: electricity is 25% more expensive in 2020, growth of 11% per decade as in the baseline scenario
3) **High Fuel Price** scenario: natural gas price higher by 25% in 2020 and 2030 than under the baseline scenario
4) **Low Additional Costs** scenario: additional costs are 25% lower than under the baseline scenario
5) (1), (2), (3) combined
6) **Best Case** scenario: (1), (2), (3), (4) combined

The summary of net benefits under all scenarios is presented in Figure 6.5.

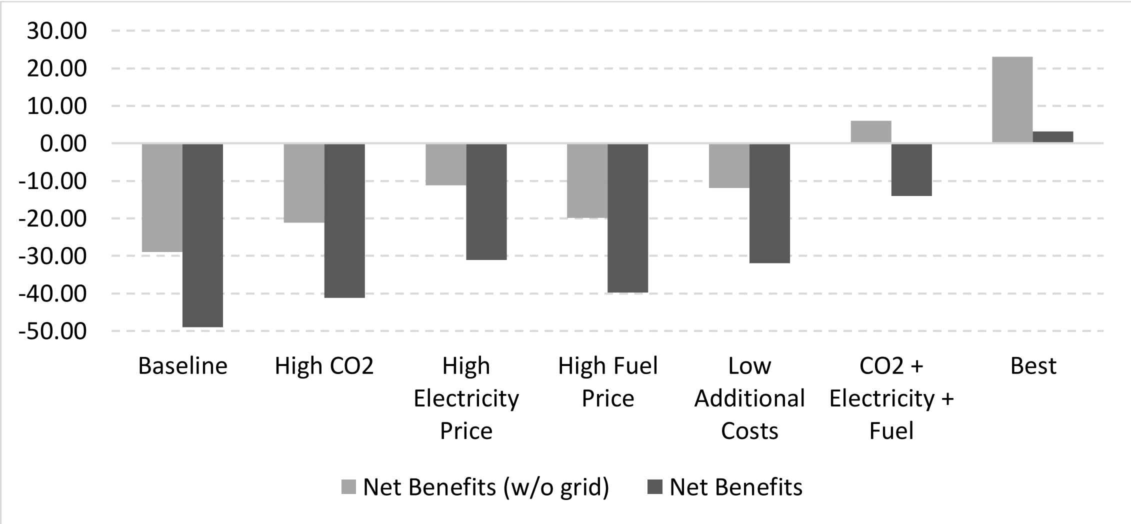


Figure 6.5: Summary of Net Benefits under Various Scenarios (in €bn)

6.4.1 High CO_2 Price Scenario

In chapter 3 we assumed a constant CO_2 price of €15 per ton. In this scenario we assume a price of €25 per ton, which appears to be the convention in the literature. Figure 6.6 summarizes the costs and benefits and shows that costs would still always be higher than the benefits. The net benefits grow from -€49 bn to -€41.12 bn. We, therefore, make the conclusion that changes in CO_2 prices do not affect net benefits drastically.

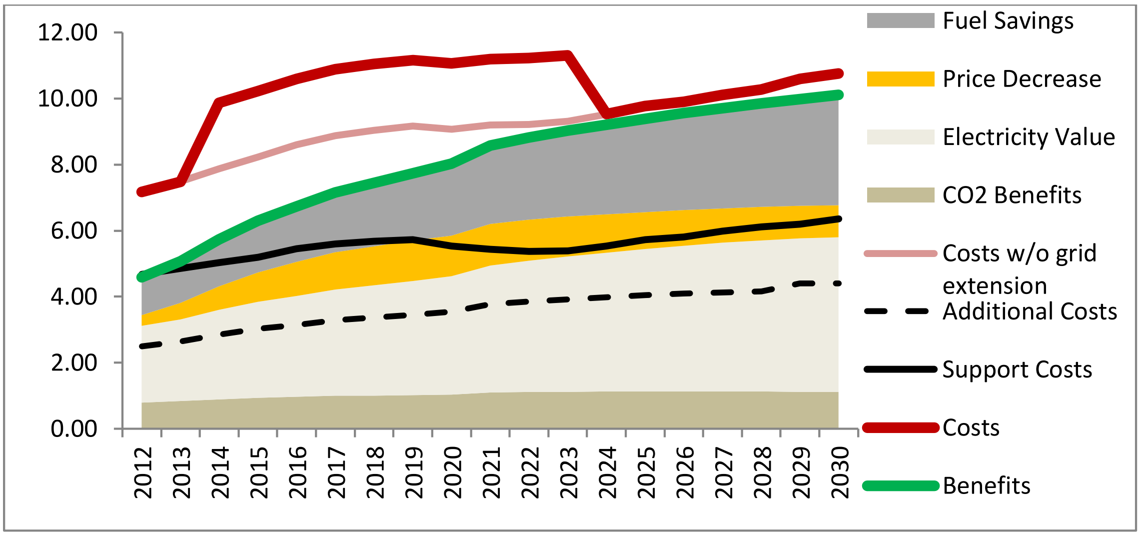


Figure 6.6: Summary of Costs and Benefits under High CO_2 Price Scenario

6.4.2 High Electricity Price Scenario

For this sensitivity analysis we assume that the price in 2020 will be 25% higher than originally assumed, €61.63/MWh instead of €49.30/MWh. Given this, the prices still grow 11% a decade, ending up at €68.40/MWh in 2030. As seen on Figure 6.7, we benefits start to overweigh the costs in 2024, and if grid extension costs are not included, in 2021, which when the technology could be considered as becoming beneficial for the society. The benefits, nevertheless, are still quite small in this scenario, ranging from €230 mio to €470 mio. Such a construct results in net benefits of -€31.12 bn in 2030.

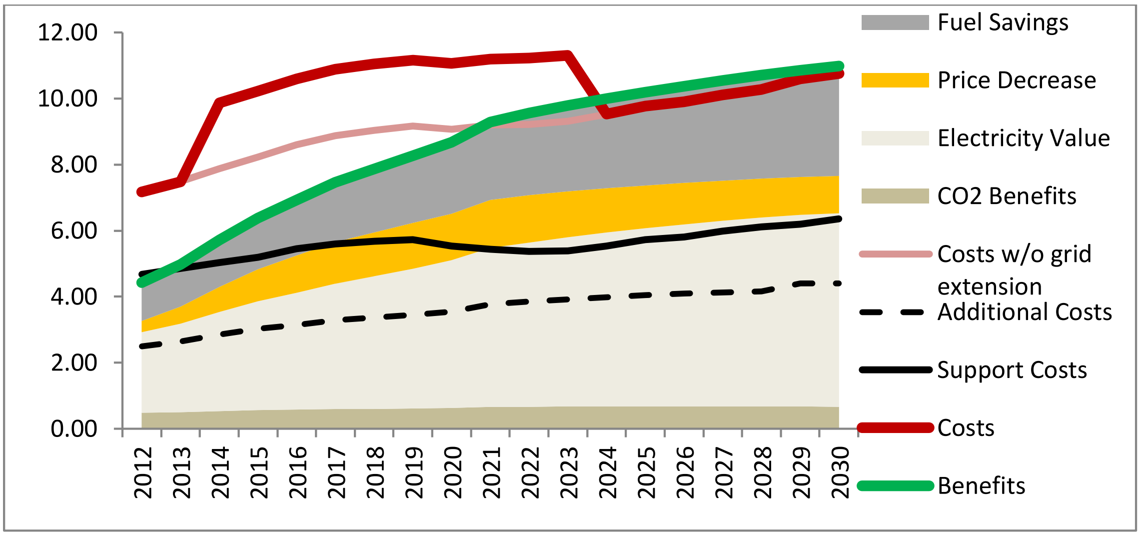


Figure 6.7: Summary of Costs and Benefits under High Electricity Price Scenario

6.4.3 High Fuel Price Scenario

Under this specification, we assume that the fuel price (in our case exclusively natural gas) would be 25% higher than the value under the baseline scenario in years 2020 and 2030. The values between 2010 and 2020, and between 2020 and 2030, modelled by compound annual growth rate, change correspondingly. The result turned out to be similar to the High CO_2 price scenario: the costs are still slightly higher than the benefits during all the years, with the net benefits amounting to -€39.78 bn. The development of costs and benefits under the High Fuel Price scenario is presented in Figure 6.8.

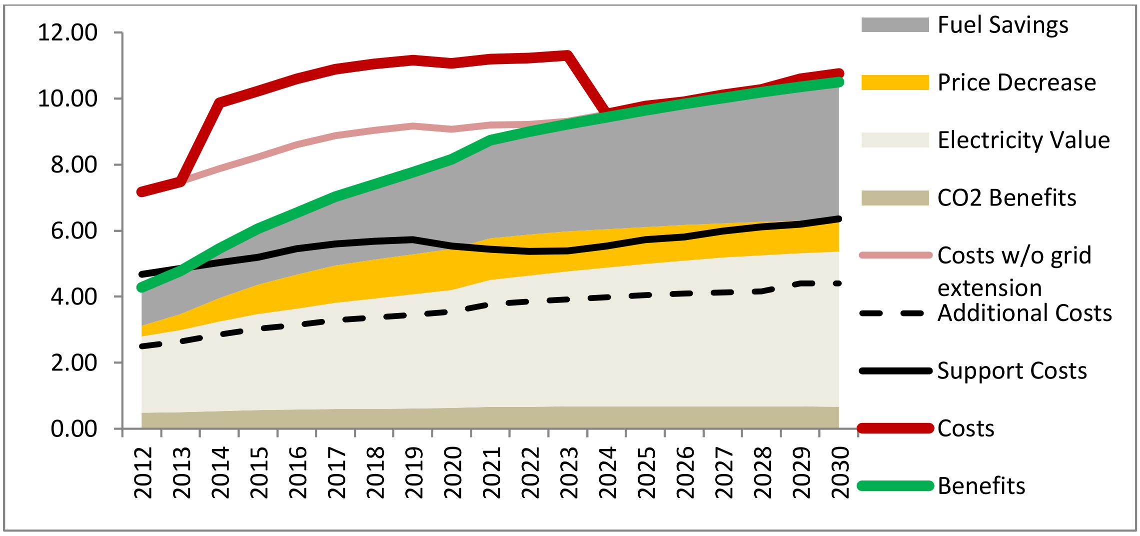


Figure 6.8: Summary of Costs and Benefits under High Fuel Price Scenario

6.4.4 Low Additional Costs Scenario

Under Low Additional Costs scenario, we assume that additional costs would be 25% lower during all years from 2012 to 2030. Such a scenario could mean rapid development of wind technologies, decrease of investment costs, interconnection with other energy markets (Nordic for example) or the development of storage technologies, allowing for cheap storage of excess production. In this specification, benefits start to overweigh the costs in 2022 if grid extension costs are not considered. Yearly net benefits thereafter do not exceed €230 mio, with cumulative benefits reaching -€31.87 bn. The costs and benefits under this scenario are presented in Figure 6.9.

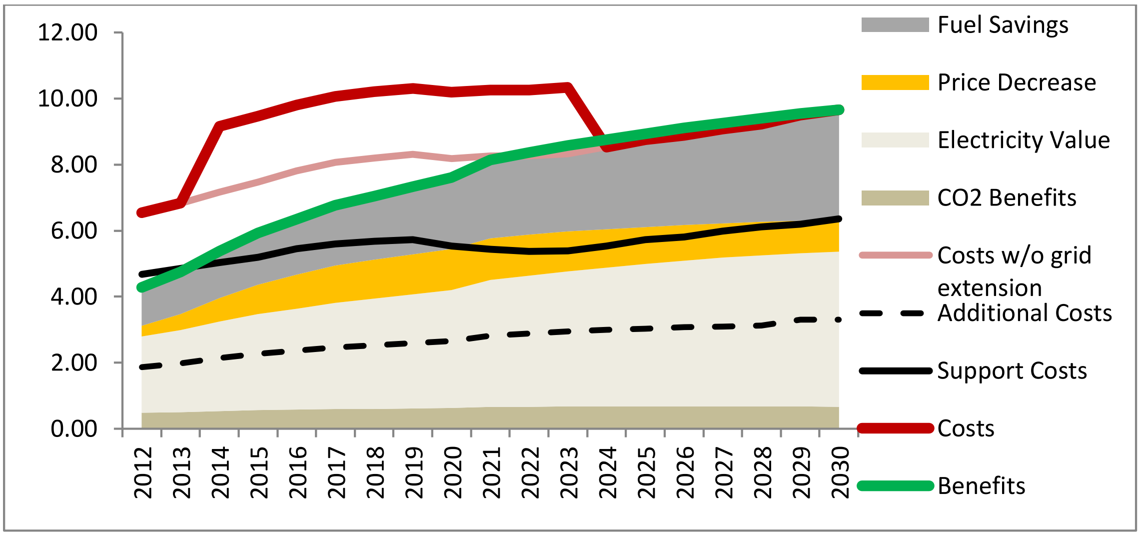


Figure 6.9: Summary of Costs and Benefits under Low Additional Costs Scenario

6.4.5 High Electricity, CO_2 and Fuel Price Scenario

Electricity prices are sometimes theorized to be influenced by both CO_2 and fuel prices, therefore we have created a scenario, which would include the first three scenario together. Under such specification, the benefits start to outweigh the costs as early as 2020, with the highest annual net benefits being €1.68 bn in 2023. The cumulative net benefits become almost positive under no grid extension specification of costs.

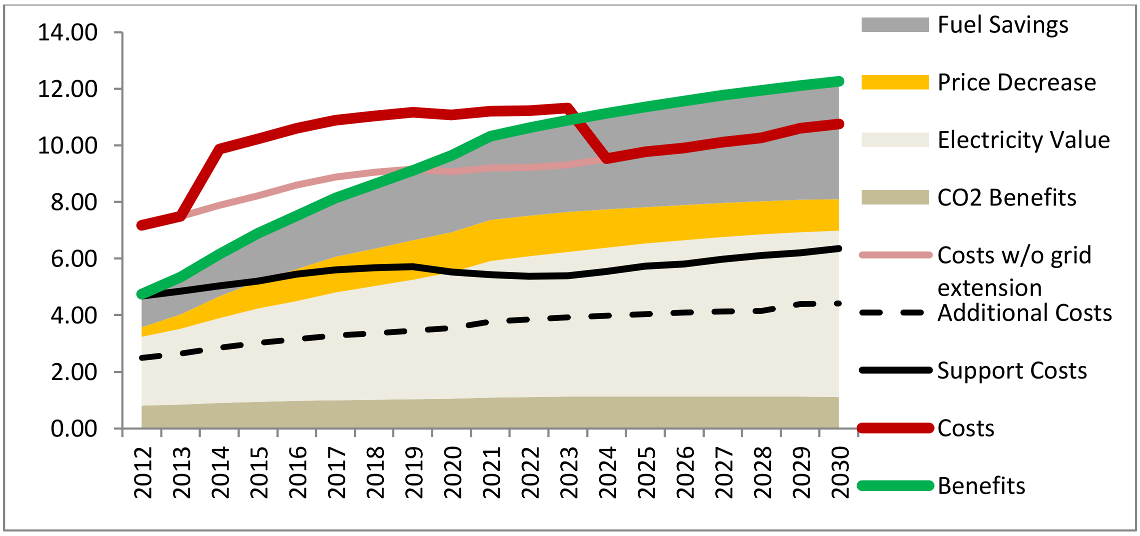


Figure 6.10: Summary of Costs and Benefits under High Electricity, CO_2 and Fuel Price Scenario

If the trend in Figure 6.10 continues, the technology could be considered as benefits as overall beneficial.

6.4.6 Best Case Scenario

The Best Case scenario combines the first four scenarios. In this specification, the benefits start overweighing costs without the grid extension in 2017 and cumulative benefits reach more than €23 bn, but are still negative (-€3.12 bn) if grid extension costs are considered. Figure 6.11 summarizes the development of costs and benefits under this scenario.

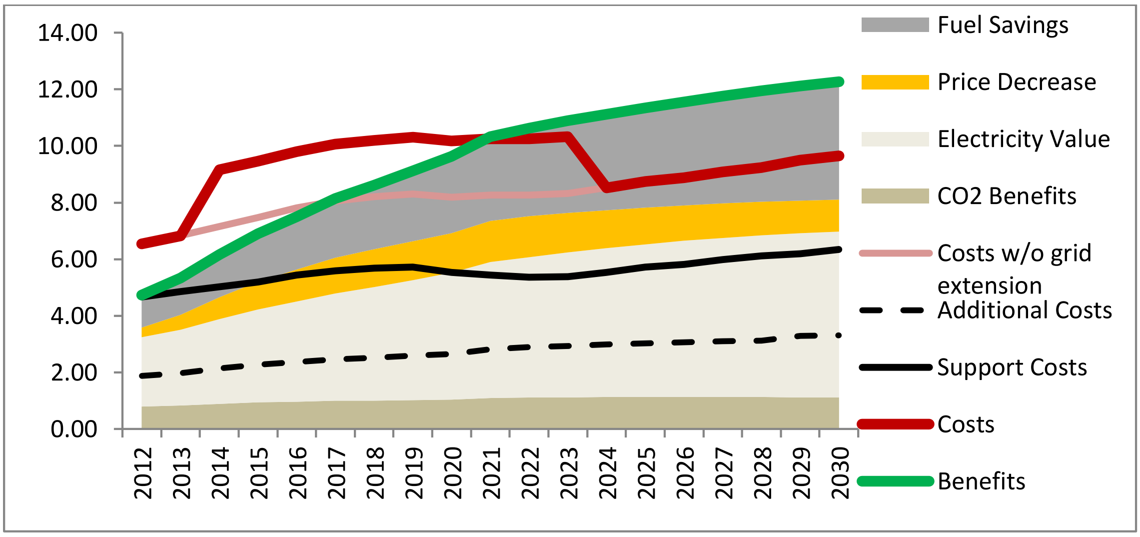


Figure 6.11: Summary of Costs and Benefits under the Best Case Scenario

7 Conclusions and Discussion

This thesis presented a cost benefit analysis of the wind power industry in Germany as a separate entity. A number of costs and benefits were selected with the aim with to obtain a business case for the industry as a whole. For this reason, for example, grid extension costs were included. While not being direct costs of the technology, wind power expansion, as it is seen within the overall plan for growth of renewable technologies, would not be possible without building additional power lines.

Onshore and offshore installations were analyzed separately since the onshore technology is well-developed worldwide and vastly present in Germany while the offshore technology is relatively new. As a result, governmental support schemes differ for these two types of installations, and two approaches to the estimations of government support were taken. Besides that, offshore installations are known to be much more efficient due the absence of obstacles in the wind's way before it reaches the turbine, scientifically known as low roughness height. This determined the capacity factors, which were estimated to be much higher for the offshore installations.

As a major determinant of the amount of governmental support through feed-in tariffs for onshore installations, the number of years of the higher initial feed-in tariff was estimated using the assumption of the Weibull distribution of wind and fitting of power curves of 5 modern wind turbines. The estimated value is 16.68 years, meaning 11.68 additional years to the guaranteed 5. It should be noted that due to the lack of data, this estimate was performed by separating zones of wind concentrations in each state of Germany. This presents the opportunity for further research in this area, specifically by obtaining accurate wind data and installation data in Germany and by more accurate determination of specific wind turbines that would be installed in Germany in future. The estimation of the corresponding number for offshore installations was performed by analyzing the remoteness and depth of future installations, the two parameters that determine the number years of the initial tariff. The result was 14.42 years, meaning 2.42 additional years to the guaranteed 12.

Under 6 specifications of the sensitivity analysis for the onshore installations (including the baseline case, which could be considered the worst case scenario), the cumulative net benefits as of 2030 are negative. In one out of these six scenarios, High CO_2, Electricity and Fuel Price scenario, the net benefits without grid extension costs are already positive and the net benefits start to be significantly positive (around €1.5 bn annually) in 2024. If grid extension costs are disregarded, the technology could be viewed as socially beneficial as early as 2020. Under the best case scenario, both cumulative net benefit types are positive.

The offshore sector did not undergo the sensitivity analysis since the trend that costs and benefits were showing was sufficient to see that the net benefits would be positive in the near future after 2030, especially if additional costs decrease and government support ends. This is also true for all onshore scenarios, even the baseline, but rests on the assumption that the operators will stay on the market. This, in its own turn, means that the technology will become cheap enough for an investment without governmental support. This also presents the opportunity for further research, specifically whether the current support level corresponds to the investment costs. Other research could also focus on the analysis of the possible development of the technology cost in future and whether it could be realistically expected to become cheap enough for independent functioning of the wind power sector.

This thesis does not explicitly research the possibility for geographic dispersion and integration with other energy markets, e.g. the Nord Pool, which could lower the cycling costs and the need for additional reserve capacity; however, in one specification of the sensitivity analyses, these costs are reduced by 25%, but this number does not stem from any particular estimations. This presents opportunities for further research in this area.

Our analysis ends in 2030. Under certain specifications, it is visible that the benefits will be higher than the costs, which means that if the horizon is widened (to, say, 2050), the net benefits per unit of power produced would be positive. Provided that such state of industry and technology can be sustained, this would mean that the net benefits would be positive in the long term perspective. What should be kept in mind, though, is that this does not mean that renewable technologies, wind in particular, should be let to expand in uncontrollable manner, i.e. the more the better. As the research by Hoogwijk, et al. (2007) shows, with the current limitatations of storing energy, high petentrations of wind power will have negative net benefits.

Bibliography

50Hertz Transmission GmbH, Amprion GmbH, Tennet TSO GmbH, TransnetBW GmbH, 2013. *Offshore-Netzentwicklungsplan 2013, erster Entwurf.* [Online] [Accessed 8 December 2013].

Boccard, N., 2009. Capacity factor of wind power: realizedvalues vs. estimates. *Energy Policy,* Issue 37, pp. 2679-2688.

Bode, S., 2006. On the impact of renewable energy support schemes on power prices', HWWI Research Paper. *HWWI Research Paper.*

Climate and Energy Ministry of Denmark, 2010. *National Action Plan For Renewable Energy in Denmark,* s.l.: s.n.

Denny, E., 2007. *A Cost Benefit Analysis of Wind Power.,* Phd Thesis: National University of Ireland.

Denny, E. & O'Malley, M., 2006. Wind Generation, Power System Operation and Emissions Reduction. *IEEE TRANSACTIONS ON POWER SYSTEMS,* 21(1), pp. 341-347.

Deutscher Wetterdienst, 2013. *Jahresmittel der Windgeschwindigkeit in 80 Meter über Grund.* [Online] Available at: http://www.dwd.de/windkarten [Accessed 11 October 2013].

Dohmen, F. & Jung, A., 2011. *North Coast Doldrums: Why Germany's Offshore Wind Parks Have Stalled.* [Online].

E.ON Netz, 2004. *Wind Report 2004,* Bayreuth: s.n.

ENERCON GmbH, 2012. *ENERCON product overview.* [Online] Available at: www.enercon.de/p/downloads/ENERCON_PU_en.pdf [Accessed 14 October 2013].

European Commission, 2010. *EU Energy Trends to 2030,* Luxembourg: Publications Office of the European Union.

European Wind Energy Association, 2009. *Pure Power: Wind energy targets for 2020 and 2030,* s.l.: s.n.

Eurostat, 2013. *Tables, Graphs and Maps Interface (TGM) table.* [Online] Available at: http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&init=1&language=en&pcode=t2020_31&plugin=1 [Accessed 10 October 2013].

Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of Germany, 2002. *Strategy of the German Government on the use of off-shore wind energy in the context of its national sustainability strategy.* s.l.:s.n.

Federal Ministry for the Environment, Nature Conservation and Nuclear Safety of Germany, 2011. *Tariffs and sample degression rates pursuant to the new Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz - EEG 2011) of 04. August 2011.* [Online] [Accessed 11 2012].

Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, n.d. *Overview of the development of offshore wind energy in Germany.* [Online] Available at: http://www.offshore-windenergie.net/en/wind-farms [Accessed 4 January 2014].

Federal Ministry of Economics and Energy, 2013. *Facts and Figures: Energy Data.* [Online] Available at: http://www.bmwi.de/BMWi/Redaktion/Binaer/energie-daten-gesamt [Accessed 24 December 2013].

Federal Ministry of Economy, Energy and Youth of Austria, 2010. *National Renewable Energy Action Plan 2010 for Austria,* s.l.: s.n.

Federal Republic of Germany, 2010. *National Renewable Energy Action Plan in accordance with Directive 2009/28/EC on the promotion of the use of energy from renewable sources,* s.l.: s.n.

Frondel, M., Ritter, N., Schmidt, C. M. & Vance, C., 2010. Economic Impacts from the Promotion of Renewable Technologies: The German Experience. *Energy Policy*, Volume 38, pp. 4048-4056.

Giebel, G., 2000. *On the Benefits of Distributed Generation of Wind Energy in Europe.* s.l.:s.n.

Hoogwijk, M., van Vuuren, D., de Vries, B. & Turkenburg, W., 2007. Exploring the impact on cost and electricity production of high penetration levels of intermittent electricity in OECD Europe and the USA, results for wind energy. *Energy,* 32(8), pp. 1381-1402.

Idaho National Laboritory, n.d. *Wind Power Software.* [Online] Available at: https://inlportal.inl.gov/portal/server.pt/community/wind_power/424/software [Accessed 14 October 2013].

Jongh, J. d. & Rijs, R., 2004. *Wind Resources.* s.l.:s.n.

Lang, M., 2013. *Offshore Grid Development Plan 2013 and Electricity Grid Development Plan 2013.* [Online] Available at: http://www.germanenergyblog.de/?p=12406 [Accessed 8 December 2013].

Liberman, E. J., 2003. *A Life Cycle Assessment and Economic Analysis of Turbines Using Monte Carlo Simulation.* s.l.:s.n.

Molly, J., 2012. *Status 31.12.2011: DEWI GmbH (German Wind Energy Institute).* [Online] Available at: http://www.dewi.de/dewi/index.php?id=66&tx_ttnews[tt_news]=119&cHash=6c6e5b5682cecccfd27d8fca43ff68ba [Accessed 14 October 2013].

Moomaw, W. et al., 2011. *2011: Annex II: Methodology. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation,* Cambridge, United Kingdom; New York, USA: Cambridge University Press.

Nicolsi, M. & Fürsch, M., 2009. The Impact of Increasing the Share of RES-E on the Conventional Power Market - The example of Germany. *ZfE Zeitschrift für Energiewirtschaft,* 03.

Parliament, E., 2008. Promotion of the Use of Energy from Renewable Sources.

Pöyry, 2010. *Wind Energy and Electricity Prices: Exploring the 'merit order effect',* s.l.: EWEA.

Siemens AG, 2011. *SWT-2.3-113-product-brochure.pdf.* [Online] Available at: http://www.energy.siemens.com/hq/pool/hq/power-generation/renewables/wind-power/wind%20turbines/SWT-2.3-113-product-brochure.pdf [Accessed 3 March 2013].

Strbac, G., 2002. *Quantifying the system costs of additional renewables in 2020,* Oxford: Ilex Energy.

Traber, T. & Kemfert, C., 2007. Impacts of the German Support for Renewable Energy on Electricity Prices, Emissions and Profits: An Analysis Based on a European Electricity Market Model. *Discussion Papers*, July, Issue 712.

Traber, T., Kemfert, C. & Diekmann, J., 2011. German Electricity Prices: Only Modest Increase Due to Renewable Energy expected. *DIW Berlin Weekly Report,* 7(6), pp. 37-45.

Vestas Wind Systems A/S, 2012. *Environment: City of Summerside Wind Farm.* [Online] Available at: http://www.gov.pe.ca/environment/undertakings-2008-summerside-wind-farm [Accessed 14 October 2013].

Wessa, P., 2013. *Maximum-likelihood Weibull Distribution Fitting (v1.0.3) in Free Statistics Software (v1.1.23-r7).* [Online] Available at: http://www.wessa.net/rwasp_fitdistrweibull.wasp [Accessed 11 October 2013].

White, D., 2004. *REDUCTION IN CARBON DIOXIDE EMISSIONS: ESTIMATING THE POTENTIAL CONTRIBUTION FROM WIND-POWER,* s.l.: Renewable Energy Foundation.

Appendix A: Main Components

	GENERAL		NEW	
Year	Onshore	Offshore	Onshore	Offshore
2012	0.2	0.33	0.22	0.33
2013	0.2	0.33	0.23	0.33
2014	0.21	0.34	0.24	0.34
2015	0.21	0.34	0.25	0.35
2016	0.22	0.35	0.26	0.37
2017	0.23	0.35	0.27	0.37
2018	0.23	0.37	0.27	0.39
2019	0.23	0.38	0.28	0.41
2020	0.24	0.39	0.29	0.42

Table A.1: General and New Capacity Factors for 2012-2020

Year	Onshore	Offshore
2021	0.30	0.33
2022	0.31	0.33
2023	0.32	0.34
2024	0.33	0.35
2025	0.33	0.37
2026	0.34	0.37
2027	0.34	0.39
2028	0.35	0.41
2029	0.35	0.42
2030	0.35	0.43

Table A.2: New Capacity Factors for 2021-2030

The table below summarizes the projections of electricity produced by onshore and offshore installations

Year	Onshore	Offshore	Onshore	Offshore
2012	**0.2**	**0.33**	**0.22**	**0.33**
2013	0.2	0.33	0.23	0.33
2014	0.21	0.34	0.24	0.34
2015	0.21	0.34	0.25	0.35
2016	0.22	0.35	0.26	0.37
2017	0.23	0.35	0.27	0.37
2018	0.23	0.37	0.27	0.39
2019	0.23	0.38	0.28	0.41
2020	0.24	0.39	0.29	0.42
2021	0.25	0.39	0.30	0.43
2022	0.25	0.40	0.31	0.44
2023	0.26	0.41	0.32	0.45
2024	0.26	0.41	0.33	0.46
2025	0.26	0.42	0.33	0.47
2026	0.27	0.42	0.34	0.47
2027	0.27	0.42	0.34	0.48
2028	0.27	0.43	0.35	0.48
2029	0.27	0.43	0.35	0.48
2030	0.27	0.43	0.35	0.48

Table A.3: Electricity Production Projections in 2012-2030

Year	Wind Production (Opt)	Wind Production (Pes)	Total Production	Penetration (Opt)	Penetration (Pes)	Additional Costs (Opt) (USD/kWh)	Additional Costs (Pes) (USD/kWh)	Additional Costs (Opt) (bnEUR/TWh)	Additional Costs (Pes) (bnEUR/TWh)	Additional Costs (Opt) (bnEUR)	Additional Costs (Pes) (bnEUR)
2012	53.06	53.06	633.95	0.084	0.084	0.065	0.065	0.0488	0.0488	2.59	2.59
2013	57.31	57.31	634.98	0.090	0.090	0.065	0.065	0.0488	0.0488	2.79	2.79
2014	63.66	63.66	636.01	0.100	0.100	0.065	0.065	0.0488	0.0488	3.10	3.10
2015	69.99	69.99	637.04	0.110	0.110	0.065	0.065	0.0488	0.0488	3.41	3.41
2016	76.07	76.07	635.00	0.120	0.120	0.065	0.065	0.0488	0.0488	3.71	3.71
2017	82.47	82.47	632.95	0.130	0.130	0.065	0.065	0.0488	0.0488	4.02	4.02
2018	89.21	89.21	630.91	0.141	0.141	0.065	0.065	0.0488	0.0488	4.35	4.35
2019	96.36	96.36	628.86	0.153	0.153	0.065	0.065	0.0488	0.0488	4.70	4.70
2020	104.44	104.44	626.82	0.167	0.167	0.065	0.065	0.0488	0.0488	5.09	5.09
2021	119.90	117.47	629.27	0.191	0.187	0.065	0.065	0.0488	0.0488	5.85	5.73
2022	130.07	125.25	631.73	0.206	0.198	0.065	0.065	0.0488	0.0488	6.34	6.11
2023	139.70	132.54	634.18	0.220	0.209	0.065	0.065	0.0488	0.0488	6.81	6.46
2024	148.77	139.33	636.63	0.234	0.219	0.065	0.065	0.0488	0.0488	7.25	6.79
2025	157.20	145.58	639.08	0.246	0.228	0.065	0.065	0.0488	0.0488	7.66	7.10
2026	164.95	151.27	640.70	0.257	0.236	0.0675	0.065	0.0506	0.0488	8.35	7.37
2027	171.99	156.39	642.32	0.268	0.243	0.0685	0.065	0.0514	0.0488	8.84	7.62
2028	178.28	160.91	643.93	0.277	0.250	0.0685	0.065	0.0514	0.0488	9.16	7.84
2029	183.81	164.84	645.55	0.285	0.255	0.07	0.0685	0.0525	0.0514	9.65	8.47
2030	188.54	168.16	647.16	0.291	0.260	0.07	0.0685	0.0525	0.0514	9.90	8.64

Table A.4: Additional Costs

Year	CO2 avoided (tons per MWh)	price per ton of CO2
2012	0.622	15
2013	0.617	15
2014	0.613	15
2015	0.608	15
2016	0.600	15
2017	0.593	15
2018	0.585	15
2019	0.579	15
2020	0.572	15
2021	0.566	15
2022	0.561	15
2023	0.556	15
2024	0.550	15
2025	0.545	15
2026	0.540	15
2027	0.535	15
2028	0.529	15
2029	0.524	15
2030	0.518	15

Table A.5: CO2 Emission Avoidance and CO2 Price

The table below presents the tariffs used in the relevant calculations of this thesis. The second column entitled Basic represents the data for the lower basic tariff, the third column stands represents the higher initial tariff and the third column represents the higher initial tariff with system services bonus added. All values are in eurocents per KWh. The fourth column specifies the law, which was the source of tariffs for the given year.

Year	Initial + System bonus	Initial	Basic	Law
1990-	9.10	9.10	6.19	Stromeinspeisungsgesetz
2000	9.10	9.10	6.19	EEG 2000
2001	9.10	9.10	6.19	
2002	8.96	8.96	6.10	
2003	8.83	8.83	6.01	
2004	8.70	8.70	5.50	EEG 2004
2005	8.53	8.53	5.39	
2006	8.36	8.36	5.28	
2007	8.19	8.19	5.17	
2008	8.03	8.03	5.07	
2009	9.70	9.20	5.20	EEG 2009
2010	9.61	9.11	5.15	
2011	9.51	9.02	5.10	
2012	9.41	8.93	4.87	EEG 2012
2013	9.27	8.80	4.80	
2014	9.14	8.67	4.73	
2015	9.00	8.54	4.66	
2016	8.41	8.41	4.59	
2017	8.28	8.28	4.52	
2018	8.16	8.16	4.45	
2019	8.04	8.04	4.38	
2020	7.92	7.92	4.31	
2021	7.80	7.80	4.25	
2022	7.68	7.68	4.19	
2023	7.56	7.56	4.13	
2024	7.45	7.45	4.07	
2025	7.34	7.34	4.01	
2026	7.23	7.23	3.95	
2027	7.12	7.12	3.89	
2028	7.01	7.01	3.83	
2029	6.90	6.90	3.77	
2030	6.80	6.80	3.71	

Table A.6: Feed-in Tariffs and the Applicable Law

Appendix B: Power Curves

This Appendix specifies the power curves of five turbines used in the calculation of the years of the initial high tariff. A subsection for each turbine is created showing the complete power curve as well as two fitted segments, unless specified otherwise.

Appendix A.1: **Enercon-82 2.0**

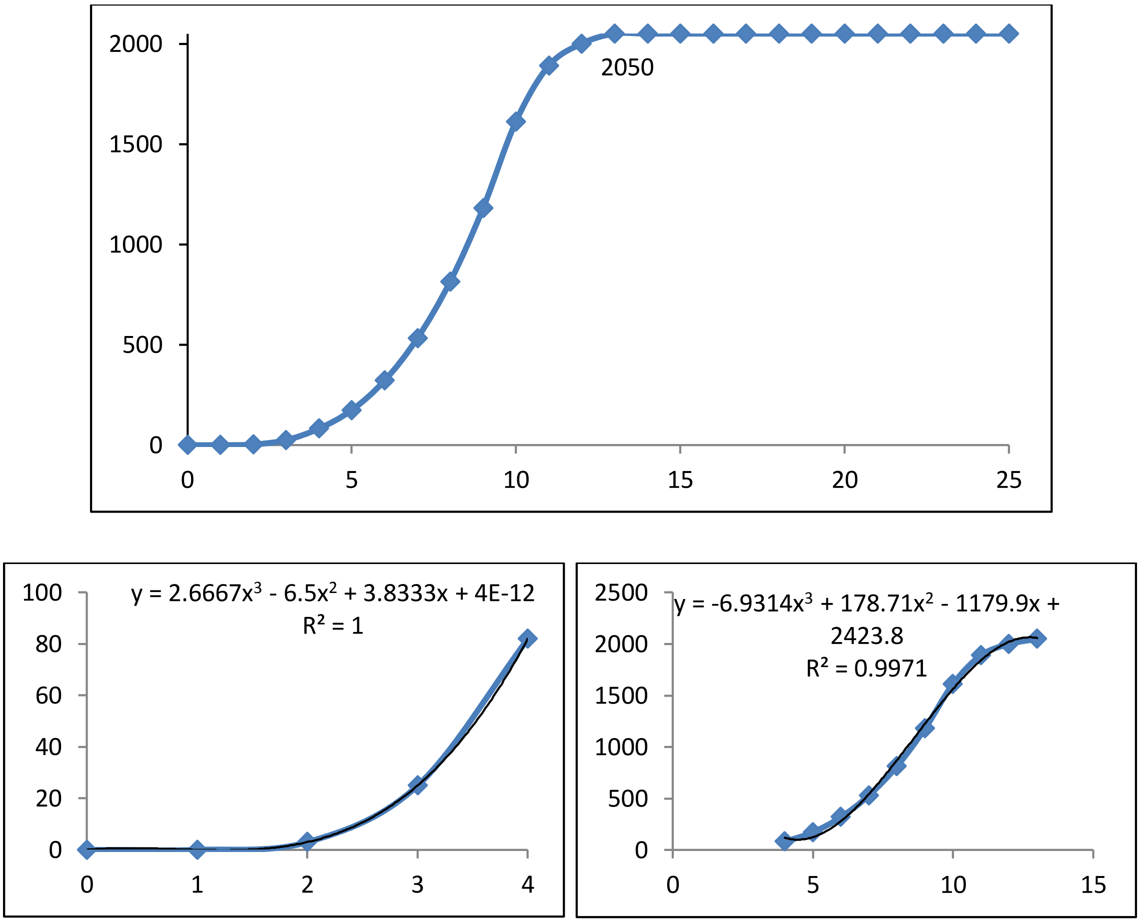


Figure B.1: Enercon E-82 2.0 Power Curve and Fitting by Segments

Appendix A.2: **Enercon E-70 2.3**

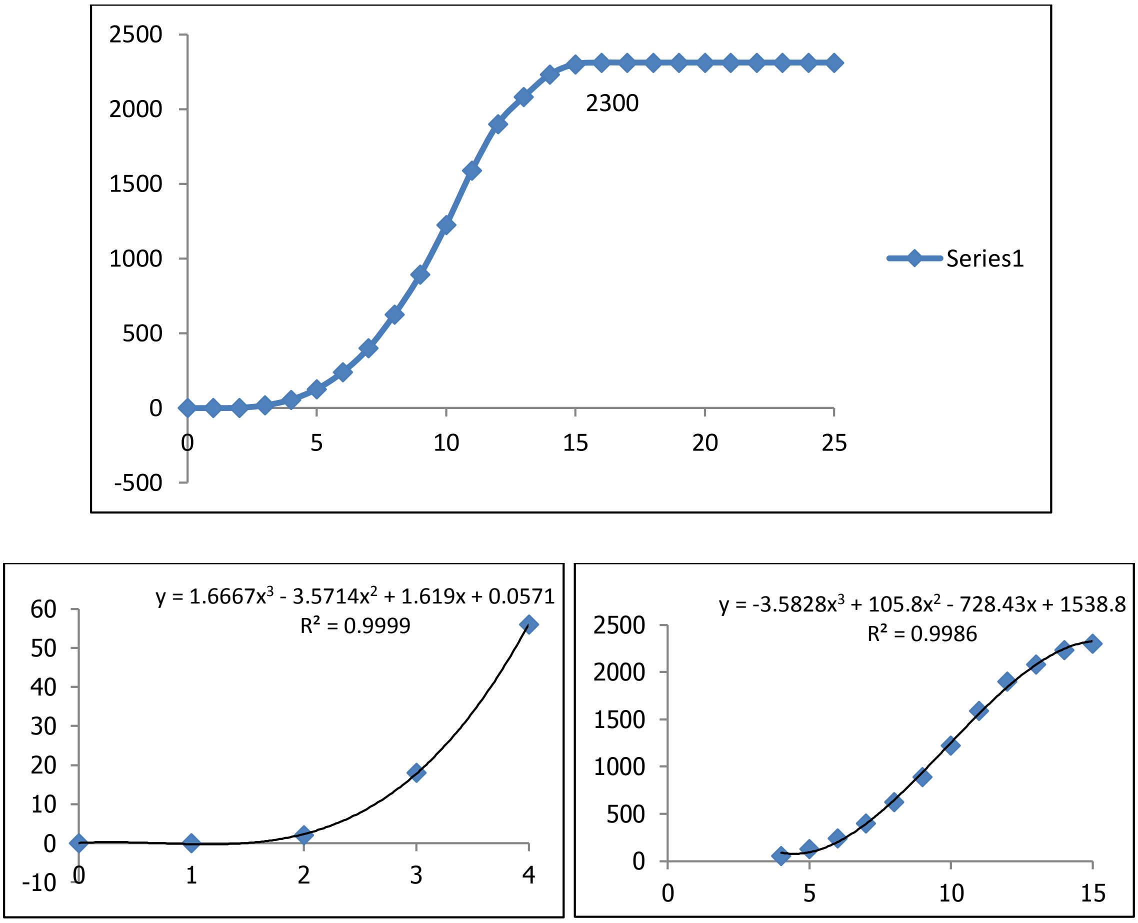


Figure B.2: Enercon E-70 2.3 Power Curve and Fitting by Segments

Appendix A.3: **Siemens SWT-2.3 93**

For Siemens SWT-2.3 93 only the segment after 4 m/s was fitted since the output for values below this are 0.

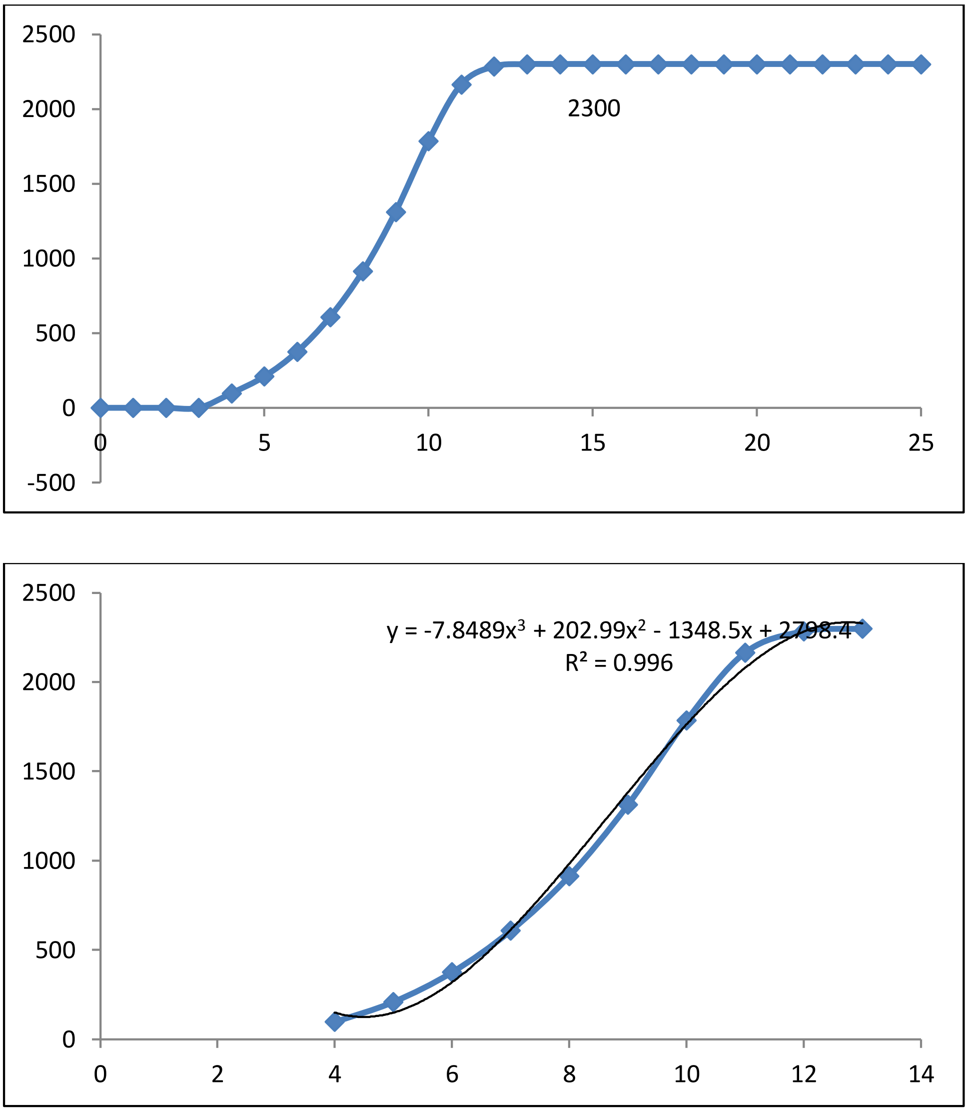
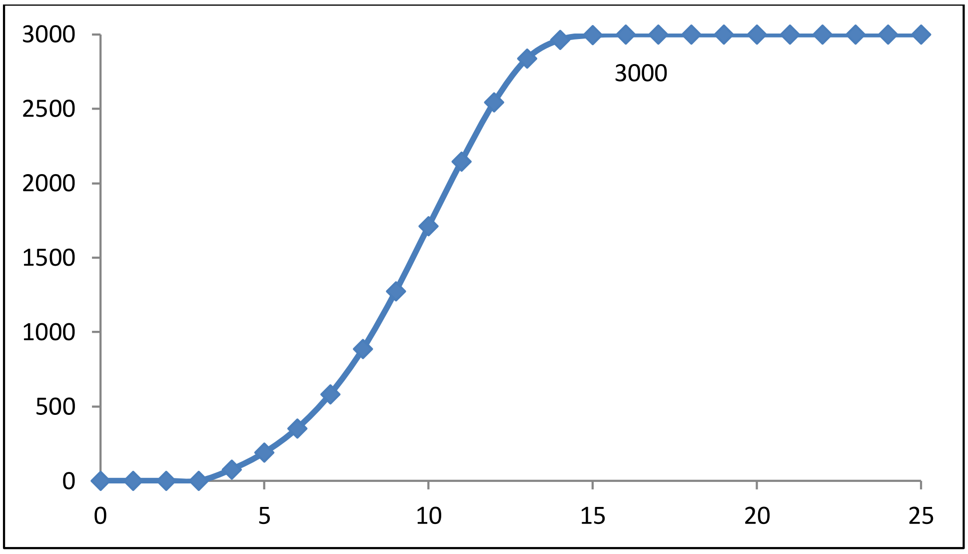


Figure B.3: Siemens SWT-2.3 93 Power Curve and Fitting by Segments

Appendix A.4: **Vestas V-90 3.0**

Just like for Siemens SWT-2.3 93, only the segment after 4 m/s was fitted for Vestas V-90 3.0 since the output for values below this are 0.



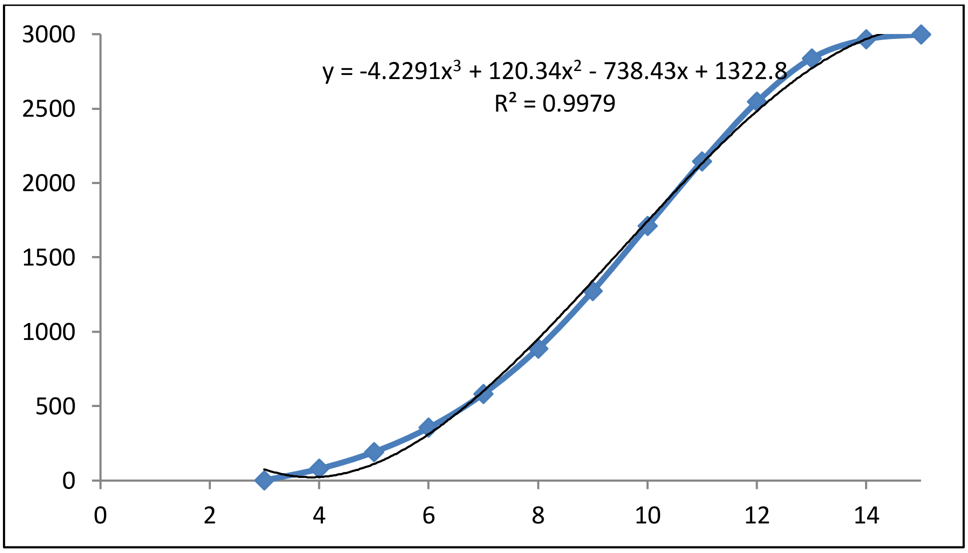


Figure B.4: Vestas V-90 3.0 Power Curve and Fitting by Segments

Appendix A.5: **Enercon E-101**

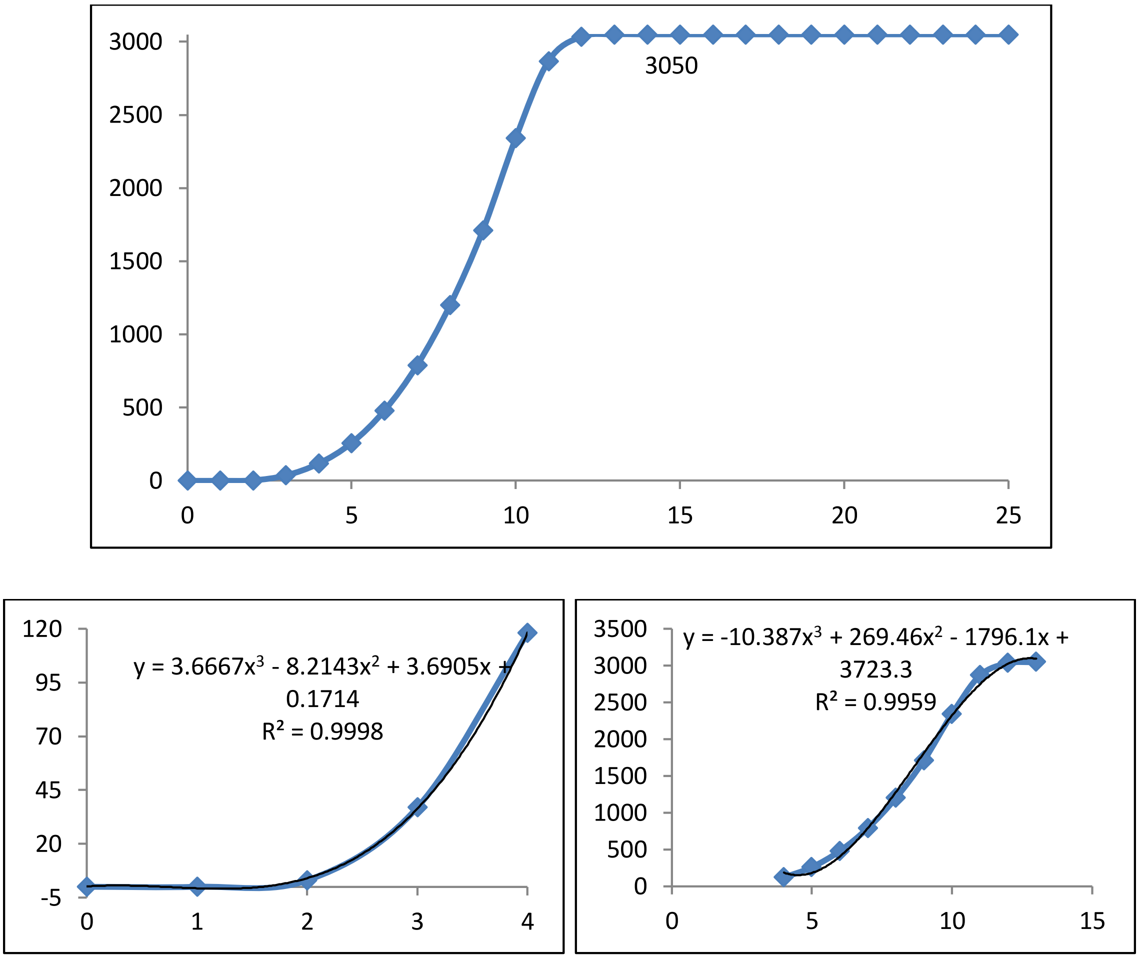


Figure B.5: Enercon E-101 Power Curve and Fitting by Segments

Appendix C: Wind Maps and Zones

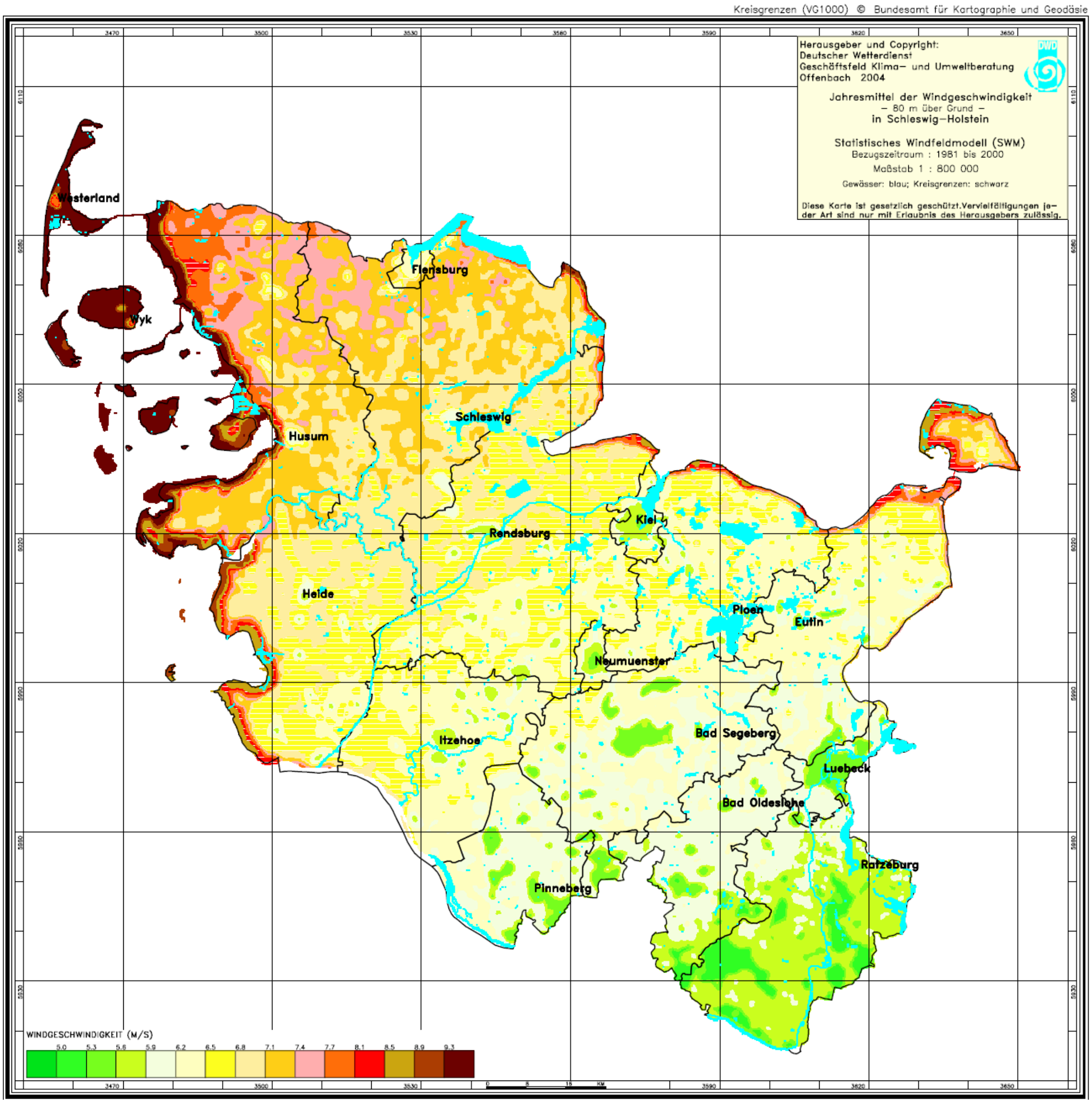


Figure C.1: Wind Map for the State of Schleswig-Holstein

Source: Deutscher Wetterdienst (2013)