Doctoral thesis

Applied Offshore Wind Economics

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Abstract

Offshore wind is considered to play an important role in the ongoing energy transition that is aimed at changing the energy mix towards the domination of renewable energy sources. However, the rapid expansion of offshore wind generates permanent new challenges that are not only technical but also economic. Therefore, the overall objective of this doctoral thesis is to contribute in the form of scientific publications to the field of Applied Offshore Wind Economics, i.e., investigating issues arising in the offshore wind sector during its expansion that are within the scope of Applied Economics. In general, the methodology for every publication is the same and follows the principle that a model is developed and applied within the scope of a case study using real-world data. Four publications are presented that provide insights into (1) the offshore wind turbine market, (2) cost efficiency and learning, (3) market value and the impact on the electricity spot market and (4) the profitability of offshore wind. Designing the models specifically for the purpose of solving the issue identified that are unbiased as to the method and result as well as applying real-world data of the highest possible quality ensures that the results and conclusions are highly interesting for public and private stakeholders in the offshore wind sector. Thus, this research contributes to the efficient expansion of offshore wind at the lowest possible cost for the society and therefore to the successful realisation of this energy transition.

Table of contents

REVIEW

Applied Offshore Wind Economics

1 Introduction

Concerns about climate change caused by greenhouse gas emissions, particularly carbon dioxide (CO_2), but also the dependency on fossil fuels jeopardising the security of supply and the risk associated with the operation of nuclear power plants that became particularly recognised after incidents such as in Fukushima promoted the necessity of an energy transition, i.e., the change of the energy mix towards the domination of renewable energy sources. [5–7] This transition affects particularly the electricity and heat sector, which produces by far the largest amount of global CO_2 emissions, with a share of 42%. [8] Considering also that 67% of the world's electricity is generated from fossil fuels and 11% with nuclear technology reveals that this energy transition constitutes a major challenge for this sector. [9] Onshore wind is thereby considered to play an important role not least because recent studies (e.g., [10]) have shown that its cost has become competitive with baseload technologies such as natural gas-fired CCGTs, coal and nuclear technology, and it is the least expensive among renewable energy technologies. However, in some countries, onshore wind seems to have reached its limits due to the lack of space on land and the resulting competing site usage. An alternative is the deployment of wind turbines in the sea, which is also referred to as offshore wind, where large continuous free areas are available. The placement far from populated areas enables the reduction of noise emissions and the visual impact, which in turn solves the problem of residents' resistance. Furthermore, the larger and steadier wind resource prevailing offshore improves generation efficiency and ensures better power reliability. Finally, offshore wind energy is also referred to as "dark green" electricity because in addition to being a non-fossil, renewable and sustainable source contributing to greenhouse gas mitigation, it contributes to the protection and conservation of marine biodiversity. [11–13] Therefore, it comes not as a surprise that merely in European waters, the offshore wind capacity has doubled since the year 2011 and is expected to almost triple again from 8.0 GW in 2014 to 23.5 GW by 2020. [14,15]

2 Objective

The large-scale deployment of offshore wind farms beginning only a few years ago and now this renewable energy source rapidly expanding implies that there are permanent new challenges emerging that are not only technical but also economic and organizational, which offer extensive areas for research. However, compared to the amount of scientific publications investigating technical issues in the field of offshore wind, the number of papers with an economic focus is rather low. Therefore, the overall objective of this doctoral thesis is to contribute in the form of scientific publications to the field of Applied Offshore Wind Economics, i.e., investigating issues arising in the offshore wind sector during its expansion that are within the scope of Applied Economics. That means that the publications presented in this thesis use the application of economic analysis to investigate solutions for specific problems in both the public and private sector. They make use of the methods of mathematics, statistics and operations research and aim to generate results that are of use in the practical field and provide factual conclusions. This coincides with the overall aim of the research field of Applied Economics, which tries to bring economic theory nearer to reality applying quantitative and empirical studies. [16] This research is essential to ensure the efficient expansion of offshore wind at the lowest possible cost for society and therefore contribute to the successful realisation of this energy transition.

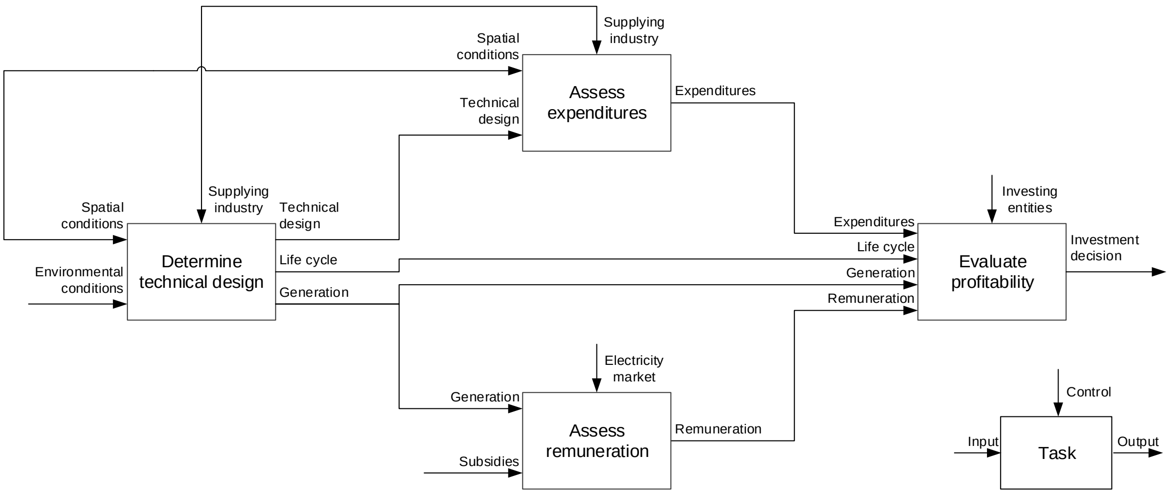

Figure 0-1: Process preceding an investment decision for an offshore wind farm (cf. [17]).[1]

More specifically, the subject of this doctoral thesis is the investigation of the factors and relationships underlying the decision of entities to invest in the deployment of an offshore wind power plant and, based on the insights gained, to identify potential improvements that support the efficient expansion of this renewable energy technology. Figure 0-1 provides a basic illustration of the process that precedes an investment decision of an entity. Basically, this decision requires the entity's evaluation of the expected offshore wind farm's profitability. In case of a power plant project, the profitability is specified by the expenditures, the amount of electricity generation and the remuneration accumulating over the life cycle. [18] The latter depends on the technical design, where based on the prevailing spatial (e.g., water depth) and environmental conditions (e.g., wind resource and wave climate) at the planning site, the robustness of the components is determined. [19] In addition, the generation amount is a consequence of the technical design, as it primarily depends on how efficient the selected wind turbines and their arrangement within the planning site transform the kinetic energy content of the wind into electrical energy. [20] Based on the technical design and the spatial conditions (e.g., distance to the operating port), it is possible to assess the expenditures incurred during the life cycle of the plant. [21,22] Those as well as the technical design are, of course, heavily influenced by the supplying industry that determines the availability of components and services as well as their price. However, to be profitable, the generation must be remunerated accordingly. As for other electricity generating plants, this depends on the valuation of the generation on the electricity market. However, at the present, the earnings obtained from trading the electricity on the spot market are not sufficient to ensure profitability. This is why subsidies are required to provide enough incentive to realise offshore wind farms. [23] The publications presented in this doctoral thesis investigate the factors and relationships shown in Figure 0-1 that determine the economic environment for offshore wind in detail.

3 Methodology

In general, the methodology for every publication is the same and follows the principle that a model is developed and, because it is applied research, that it is applied within the scope of a case study using real-world data. Hence, once an issue within the scope of Applied Offshore

[1] Boxes represent tasks, and arrows entering the left side of a box input factors that determine the output factors, which are leaving the box on the right side. Arrows entering the box on the top represent controls that specify conditions influencing the output factors as well.

Wind Economics is identified a literature study is conducted to learn how this issue was modelled to date, whether there are other possibilities that might be more suitable and how similar issues occurring in other sectors were analysed. In addition to that, it is necessary to find a reliable and profound database for the case study. Based on these findings, a model is designed with the aim of generating significant results, which enable deriving factual conclusions of how the issue identified initially could be optimally addressed. Therefore, the individual developed models presented in the publications differ much as they are based on methods originating from the fields of inter alia operations research, statistics, optimisation, financial modelling and energy yield assessment for wind power plants. Designing the models specifically for the purpose of solving the issue identified that are unbiased as to the method and result as well as to applying real-world data of the highest possible quality ensures that the contributions presented in the following provide valuable insights for public and private stakeholders acting in the offshore wind sector.

4 Abstracts

This doctoral thesis comprises four publications that present insights into the offshore wind turbine market [1], cost efficiency and learning [2], market value and impact on the electricity spot market [3] and the profitability [4] of offshore wind. The abstracts of these contributions are provided in the following.

4.1 PUBLICATION 1 – The right size matters: Investigating the offshore wind turbine market equilibrium [1]

Although early experiences indicate that the maturity of deployed technology might not be sufficient for operating wind farms in large scale far away from shore, the rapid development of offshore wind energy is in full progress. Driven by the demand of customers and the pressure to keep pace with competitors, offshore wind turbine manufacturers continuously develop larger wind turbines instead of improving the present ones which would ensure reliability in harsh offshore environment. Pursuing the logic of larger turbines generating higher energy yield and therefore achieving higher efficiency, this trend is also supported by governmental subsidies under the expectation to bring down the cost of electricity from offshore wind. The aim of this article is to demonstrate that primarily due to the limited wind resource upscaling offshore wind turbines beyond the size of 10 MW is not reasonable. Applying the planning methodology of an offshore wind project developer to a case study wind farm in the German North Sea and assessing energy yield, lifetime project profitability and levelized cost of electricity substantiate this thesis. This is highly interesting for all stakeholders in the offshore wind industry and questions current subsidy policies supporting projects for developing turbines up to 20 MW.

4.2 PUBLICATION 2 – Evaluating capital and operating cost efficiency of offshore wind farms: A DEA approach [2]

An actual growth rate greater than 30 % indicates that offshore wind is a reasonable alternative to other energy sources. The industry today is faced with the challenge of becoming competitive and thus significantly reduce the cost of electricity from offshore wind. This situation implies that the evaluation of costs incurred during development, installation and operation is one of the most pressing issues in this industry at the moment. Unfortunately, actual cost analyses suffer from less resilient input data and the application of simple methodologies. Therefore, the objective of this study was to elevate the discussion, providing stakeholders with a sophisticated methodology and representative benchmark figures. The use of Data Envelopment Analysis (DEA) allowed for plants to be modelled as entities and costs to be related to the main specifics, such as distance to shore and water depth, ensuring the necessary comparability. Moreover, a particularly reliable database was established using cost data from annual reports. Offshore wind capacity of 3.6 GW was benchmarked regarding capital and operating cost efficiency, best-practice cost frontiers were determined, and the effects of learning-by-doing and economies of scale were investigated, ensuring that this article is of significant interest for the offshore wind industry.

4.3 PUBLICATION 3 – The market value and impact of offshore wind on the electricity spot market: Evidence from Germany [3]

Although the expansion of offshore wind has recently increased in Germany, as in other countries, it is still forced to defend its role in long-term energy policy plans, particularly against its onshore counterpart, to secure future expansion targets and financial support. The objective of this article is to investigate the economic effects of offshore wind on the electricity spot market and thus open up another perspective that has not been part of the debate about offshore vs. onshore wind thus far. A comprehensive assessment based on a large amount of market, feed-in and weather data in Germany revealed that the market value of offshore wind is generally higher than that of onshore wind. Simulating the merit order effect on the German day-ahead electricity market for the short term and long term in the years 2006 – 2014 aimed to identify the reason for this observation and show whether it is also an indication of a lower impact on the electricity spot market due to a steadier wind resource prevailing offshore. Although the results suggest no difference regarding the impact on market price and value, they indeed reveal that offshore wind imposes less variability on the spot market price than onshore wind. In addition, the long-term simulation proved that the ongoing price deterioration cannot be blamed on the characteristic of variable wind production.

4.4 PUBLICATION 4 – The price of rapid offshore wind expansion in the UK: Implications of a profitability assessment [4]

With a total installed capacity of 5.1 GW and an expansion pipeline of 11.9 GW, offshore wind constitutes a story of success in the UK. The necessary foundation for this outstanding attainment is an energy policy that offered entities enough incentive in the form of profit and certainty so that investing in a rather immature technology became attractive. In this article, the profitability of 14 early-stage offshore wind farms (1.7 GW) is assessed with the objective to review at what price this rapid expansion occurred. Within the framework of a developed standardised financial model, the data from the offshore wind farms' original annual reports were extrapolated, which made it possible to simulate their profitability individually. The results reveal a return on capital in the range of more than 15% and a decreasing trend. This implies that the levelised cost of electricity from the first offshore wind farms were underestimated in the past. In addition, a stress test revealed that the operation of some farms might become unprofitable towards the end of their planned lifetimes. The particular reliable data basis and novel modelling approach presented in this article ensure that this study is of high interest for offshore wind stakeholders.

5 Scientific contribution

An overview of the scientific contribution of this doctoral thesis is provided by Table 0-1, which lists the uniqueness and highlights of each publication. The first publication "The right size matters: Investigating the offshore wind turbine market equilibrium" [1] investigates the trend of upscaling offshore wind turbines from a market point of view. This constitutes a novelty, because although this is a popular research topic, all publications in this field are written from a turbine designer point of view. Hence, it has never been questioned whether offshore wind turbines with a capacity of up to 20 MW are economically feasible and thus competitive in a market environment. Indeed the results reveal that mainly due to limited available wind resource upscaling offshore wind turbines beyond a size of 10 MW does not significantly increase efficiency. This gives advice to the industry that seems to somehow develop beyond the market, i.e., instead of improving the maturity of the current technology to sustain the harsh offshore environment, the size of turbines is increased, which entails substantial technical challenges. Furthermore, it casts a shadow on current subsidy policies supporting research projects for developing turbines up to 20 MW.

Publication	Uniqueness	Highlights
[1]	– First article to analyse upscaling of offshore wind turbines from a market point of view	– State-of-the-art offshore wind planning and turbine selection methodology is presented. – Energy yield, profitability (IRR) and LCOE for 3 – 20 MW turbines are evaluated. – Upscaling of offshore wind turbines is likely to stop due to limited wind resource. – Results indicate a market equilibrium for 10 MW offshore wind turbines. – Installed capacity resp. energy yield per km^2 is flattening with increasing turbine size.
[2]	– First article (to the author's knowledge) to apply DEA to offshore wind farms – Particularly reliable database used; all cost inputs were obtained from annual financial statements – Method for scanning and visualising a best-practice cost frontier is presented	– Innovative performance evaluation methodology was developed, ensuring necessary comparability within database – 3.6 GW offshore wind capacity is considered (of 5.0 GW cumulative installed capacity in Europe through 2012) – New operational data, which are usually difficult to obtain, from offshore wind farms are presented – Provision of reliable benchmark figures of capital and operating costs for offshore wind stakeholders – Verification and quantification of economies of scale and learning-by-doing in offshore wind
[3]	– First article to present market value of offshore wind – First article to simulate the merit order effect caused by offshore wind	– Market value of offshore wind based on feed-in and weather data is assessed. – Merit order effect caused by wind energy is simulated for 2006 – 2014. – Results indicate same impact of on- and offshore wind on market price and value. – Steadier wind resource offshore imposes less variability on market price. – Characteristic of variable wind feed-in cannot be blamed for price deterioration.
[4]	– This is the first article to assess the realised profitability of offshore wind and its impact on the levelised cost of electricity to a large extent. – This is the first article to apply a modelling approach based on extrapolation of financial data from annual reports within the framework of a standardised financial model for offshore wind farms.	– The profitability of 14 early-stage offshore wind farms (1.7 GW) is assessed. – A standardised financial model of an offshore wind farm in the UK is presented. – Analysis is based on the extrapolation of financial data from annual reports. – The results indicate a return on capital of more than 15% and a decreasing trend. – Technology's immaturity may cause unprofitable operation towards the end of farm lifetimes.

Table 0-1: Highlights and Uniqueness.

"Evaluating capital and operating cost efficiency of offshore wind farms: A DEA approach" [2] is the first article applying the operations research tool DEA to offshore wind farms with the objective of, on the one hand, developing a useful methodology for evaluating how efficiently costs are used for developing, installing and operating offshore wind farms and, on the other hand, of using the methodology as basis for an in-depth cost analysis. Hence, in addition to calculating the relative capital and operating cost efficiencies by DEA, a specially developed method for scanning and visualising a best-practice cost frontier enables providing offshore wind stakeholders with benchmark figures as a function of the main specifics of offshore wind farms. Moreover, a Tobit regression analysis verifies and quantifies the expected relationships between the efficiency scores calculated by DEA and certain factors of interest, such as an increasing capital cost efficiency as a function of time, a decreasing operating cost efficiency as a function of the operating year and the presence of economies of scale and learning-by-doing. To ensure the significance and usefulness of the publication’s results, all cost inputs originate directly from already operational offshore wind projects’ annual financial statements deposited at the respective register of companies. Overall, this publication closes a gap in the literature because it provides offshore wind stakeholders a reasonable method for reviewing the relative performance of offshore wind farms in terms of costs and reliable figures as a benchmark calculated based on a particularly reliable database. Thus, it contributes to the key challenge of improving cost efficiency to gain competitiveness with an analysis of high scientific quality that stands out compared to other cost analyses in this field.

The publication “The market value and impact of offshore wind on the electricity spot market: Evidence from Germany” [3] contributes to the research field that investigates the integration of renewables into the electricity market, which has gained in importance substantially in the last few years. The main reason for this might be that the economic effects of renewables on the electricity market, especially with regard to a deterioration of the market price in general and of renewables’ market values in particular caused by the so-called merit order effect is becoming increasingly more noticeable. The objective of this publication is to investigate and quantify these economic effects for offshore wind and compare it with its onshore counterpart. Although it is currently a popular field of research, it is the first article to present the market value of offshore wind and to simulate the merit order effect caused by offshore wind. The results reveal that the steadier wind resource prevailing offshore seems to result in less variability induced by the feed-in on the spot market price compared with its onshore counterpart. Because increasing volatility entails significant challenges for the electricity market environment, this finding is indeed an argument in favour of offshore wind that has not been part of comparisons to date. Furthermore, the simulation of the long-term effects demonstrated that the deterioration of the spot market price is not related to the property of renewable energy feed-in but to the consequence of a rapid expansion of renewable electricity supply without the envisaged concomitant phase-out of coal and nuclear power plants. This is remarkable because publications in this field tend to link the expansion of renewable energy with a decreasing market price, which casts a shadow on the energy transition.

Finally, the publication “The price of rapid offshore wind expansion in the UK: Implications of a profitability assessment” [4] addresses the main challenge policymakers are faced with when designing support schemes for the efficient expansion of renewable energy, i.e., finding a good balance between offering enough incentive but at the same time enforcing improvements and keeping the profits of investing entities at a minimum. Motivated by reviewing the subsidy scheme in the UK that facilitated a remarkable expansion of offshore wind in recent years, this publication is the first to assess the actual realised profitability of operational offshore wind power plants from an ex post point of view and its impact on the levelised cost of electricity to a large extent. Applying a novel modelling approach based on the extrapolation of financial data from annual reports within the framework of a standardised financial model that considers financing structure, accounting and taxation ensures the lowest possible falsification of the results. In the end, the analysis shows that the profits of investing entities were kept within an acceptable range and provides the real levelised cost of electricity that includes the real financing cost based on the remuneration rewarded to the investing entities in the UK. However, the results of a sensitivity analysis indicate the importance of sustaining a reasonable compensation level offered by the expiring subsidy scheme in the UK also for the future, because otherwise this may lead to an unprofitable operation of the power plants before the end of the planned lifetimes. Overall, this publication contributes to the literature with a sophisticated methodology that enables reliably assessing the impact of an already implemented subsidy scheme from a post perspective.

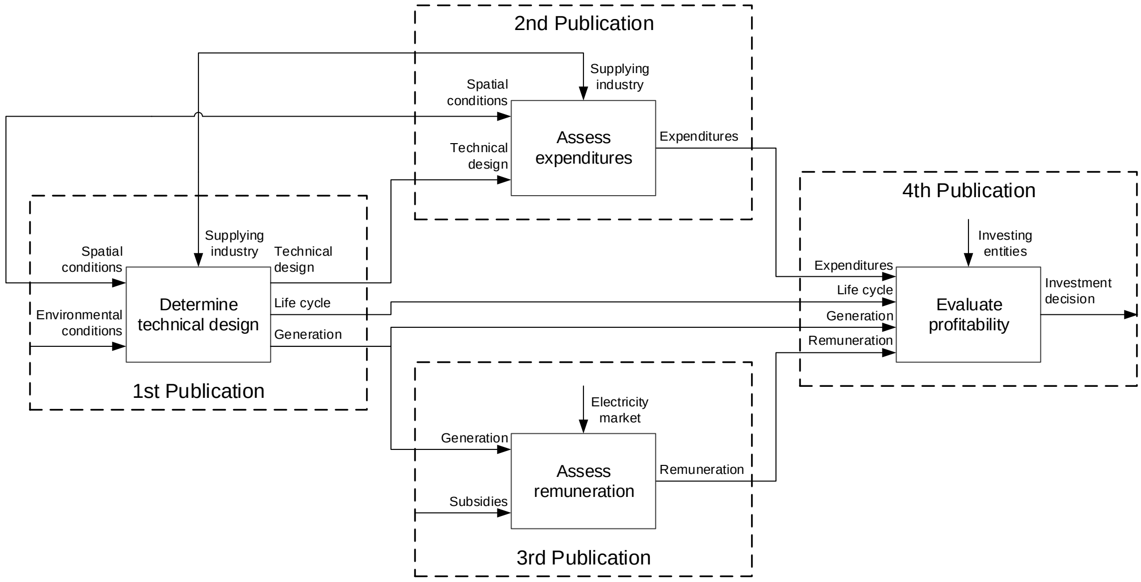

Figure 0-2: Publications' thematic focus with respect to the objective.

Overall, coming back to the objective of this doctoral thesis, Figure 0-2 shows that each publication focuses on another task of the process preceding the decision of an entity to invest in an offshore wind power plant. In that way, a large part of the factors and relationships underlying this decision is investigated, and based on this, several potential improvements are identified. Each publication being published in a renowned peer-reviewed scientific journal in the field of energy research indicates that they present valuable novelties and are of high scientific quality. It is hoped that the insights in the economic environment of offshore wind presented in these publications could contribute to the efficient expansion of offshore wind at the lowest possible cost for the society and therefore also to a successful realisation of this energy transition.

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PUBLICATION 1

The right size matters: Investigating the offshore wind turbine market equilibrium

published in

Energy
Volume 68, 15 April 2014, Pages 910–921

Abbreviations: Federal Maritime and Hydrographic Agency (BSH); Exclusive Economic Zone (EEZ); European Wind Energy Association (EWEA); internal rate of return (IRR); kilowatt (kW); levelized cost of electricity (LCOE); megawatt (MW); Offshore wind farm (OWF); offshore wind turbine generator (OWTG)

1 Introduction

The European Wind Energy Association (EWEA) reveals in their annual report about key trends and statistics in the European offshore wind industry 2012 [1], that the average size of wind turbines installed in European waters has continuously increased. During 2012, the average capacity of new wind turbines installed was 4 MW and it is very likely that this trend continues, since EWEA also reports that by the end of 2012 76 % of the announced new offshore wind turbine generators (OWTG) have a rated capacity of over 5 MW. Under the expectation of concomitant cost reductions [2,3], this trend is also fostered by governmental subsidy programs such as the European Wind Initiative [4], which is a ten years research and development programme of the European Union, that grants subsidies for developing and testing large-scale wind turbines (10 - 20 MW). For example the AZIMUT Offshore Wind Energy 2020 project [5], which has the objective to develop a 15 MW OWTG, and the already completed UpWind project [6] is supported by this European initiative. The latter investigated design limits and solutions for very large wind turbines and showed that even 20 MW wind turbines are feasible from a technical point of view.

As a consequence, upscaling of wind turbines is a research topic with increasing popularity. For example [7], where this trend is investigated with the aim to provide recommendations for optimal design of large wind turbines, [8] where a detailed analysis of costs in relation to upscaling is presented or [9] where an overview of upscaling trends for wind turbine gearboxes is given. This field of study is also related to the problem of finding optimal dimensions for wind turbines, e.g. in [10] it is argued why wind turbines with a low specific capacity are beneficial, in [11] an optimizer routine is presented which allows to determine the optimal rotor size for a given wind turbine rating, in [12] the optimal hub height for onshore wind turbines is investigated and in [13] the size of rotor/generator is site specific optimized. However, all these publications are written from the turbine designer point of view, whereas this article questions if larger OTWGs can ever be a competitive product assuming reasonable market conditions.

Therefore this article investigates the trend of growing OWTGs from the market point of view and answers the question if 20 MW OWTGs are ever reasonable or if there exists a market equilibrium that lies below this size. This market equilibrium would be of significant interest for stakeholders in the offshore wind industry. Early experiences revealed that the technology has not yet the maturity to sustain the harsh offshore environment. [14] Due to the rapid development of this industry, wind turbine manufacturers are faced with tight market conditions and are forced to continuously bring larger turbines onto the market. Supported by the prevailing tendering system of their customers, i.e. offshore wind project developers, where OWTG purchase decisions are mainly based on purchase price rather than future operating costs, improving the technology regarding reliability is therefore often missed out. In addition to that, gaining efficiency and profitability through economies of scale is hard to realize when customers already purchase larger turbines while production of the current generation has started only recently. The intention of this article is to show that there is a market equilibrium that might be reached soon. Hence the focus should be on improving the technology at this level instead of investing in the development of larger turbines. This might also give advice to political decision makers, who intend to bring the cost of electricity from offshore wind to a competitive level, how to optimally design support schemes for offshore wind. A first indication for the actual presence of a market equilibrium is the fact that this seems to be already reached for onshore wind turbines. Since a few years manufacturers have focused on offering a size between 2 and 3 MW for the onshore market. [15,16]

This investigation requires the consideration of both economic and technical aspects. Considering offshore wind industry solely from an economic point of view an increasing size of wind turbines seems reasonable. Although larger turbines cost more in terms of acquisition and operation, they generate more energy and consequently also gain more revenues. Hence the growth of turbines would only stop if costs increase disproportional with size or the additional gain in revenues is too little. But physics reveals some additional limitations apart from the engineering challenges that come along with the design of larger turbines. Firstly, a wind turbine transforms the kinetic energy content of the wind into electrical energy, which results in less kinetic energy and reduced wind speed downwind. Hence if a wake intersects with the rotor of a downwind turbine in the plant it is said to be shadowed by the turbine producing the wake and results in less energy output of the downwind turbine. [17] The larger the turbines the larger the wakes and this in turn means that the spacing between the turbines within the farm has to be increased in order to obtain the same energy yield. Based on a predefined planning area this would result in fewer turbines to be optimal within the farm. Secondly, the wind resource, which is the actual long-term kinetic energy content of the wind at a specific location and height, is limited. [18] Thus the size of wind turbines will only grow until the wind resource is not sufficient to efficiently operate the large turbines.

Offshore wind farm (OWF) project developers, who determine the demand for OWTGs, are faced with exactly these contrary economic and technical relations when planning a plant. Hence the idea was to use the planning methodology of an OWF project developer and assuming that the only decision criteria for selecting a wind turbine is the profitability of the plant over its whole life cycle. Applying this methodology with different sizes of OWTGs reveals a market equilibrium for OWTGs in terms of size, where OWF developers do not have an incentive to purchase larger wind turbines as this would not increase profitability. In addition to this analysis investigating the demand side, also the optimal size of OWTGs from the view of energy policy planners was analysed assuming that their objective is to exploit sea areas as efficiently as possible. Thus also the levelized cost of electricity (LCOE) for different OWTG sizes was assessed.

In order to generate reasonable and significant results with the developed model the methodology had to be applied to real data. This is why it was assumed to plan an OWF in the Exclusive Economic Zone (EEZ) of the German North Sea. Since Germany has envisaged installing 20 – 25 GW offshore wind capacity until 2030, the German offshore wind industry is one of the most promising markets for OWTGs in Europe. [19] There was taken particular care about the selection of data, the design of the methodology and assumptions in the sense being as close as possible to reality.

After a short clarification what is exactly understood by wind turbine size and the state of the art OWTG selection process, section 2 describes the methodology used to identify the market equilibrium and the selected case study data. Section 3 provides the results of the analysis and in section 4 a critical reflection based on a sensitivity analysis verifies the robustness of the results and individual conclusions for stakeholders in the offshore wind industry are discussed.

1.1 Clarification of wind turbine size and selection process

1.1.1 Wind turbine size

First of all it has to be defined how the size of a wind turbine is specified. As indicated earlier, the size of a wind turbine is usually determined by its rated power (also referred to as installed capacity) specified in kilowatt (kW) or megawatt (MW). This defines the level of power the turbine and its components is designed for and thus is also the nameplate capacity of the generator. Therefore it is the maximum power a wind turbine is able to produce. The basic equation for power generation P from wind

$$P = \frac{1}{2} \cdot A \cdot \rho \cdot v^3 \cdot C_p \tag{1}$$

where A designates the swept area of the rotor, v the wind speed, ρ the air density and C_p the rotor power coefficient, reveals that the installed capacity also determines the geometric proportions. In order to ensure efficiency of the turbine the rotor area has to be increased with rated power. In addition to that, also the hub height, which is the distance between ground and rotor centre, has to be raised, because on the one hand a certain distance between rotor tip and ground has to be adhered and on the other hand increasing wind speed with height ensures sufficient power input. [20]

1.1.2 OWTG selection process

Prior to developing a research methodology for the OWTG market equilibrium, it is important to understand how a purchase decision concerning the selection of an OWTG type is usually made. Figure 1-1 provides a visualisation of the selection process using IDEF0 modelling technique[2] [21] assuming that the main decision criterion is the overall project profitability. For this process basically two models are needed: a spatial planning model and an economic model. The spatial planning model calculates the optimal energy yield based on OWTG data, provided by turbine vendors, wind data of the site and an initial number of turbines. Hence this model uses an optimization algorithm in order to determine the ideal layout of the farm with regards to maximum energy output while observing the constraints of the project area. The optimal energy yield is used as an input for the economic model. This model calculates the profitability of the project using cost and remuneration data. In order to find the most profitable layout of the plant the economic model varies the number of turbines and feeds back the information to the spatial planning model. After some iterations the maximum profitability including optimal number and positioning of turbines for each OWTG type is calculated. Usually also strategic considerations as for example financial standing and quality ratings of the potential suppliers are contributing to the decision, but this was not considered in the model developed in the following. [22]

[2] This function modelling language is capable of graphically representing enterprise operations and has the main advantage that additional to input/output relations it is also possible to depict controls, which specify conditions required for the function to produce correct outputs, and mechanisms, which supports the execution of the function such as resources.

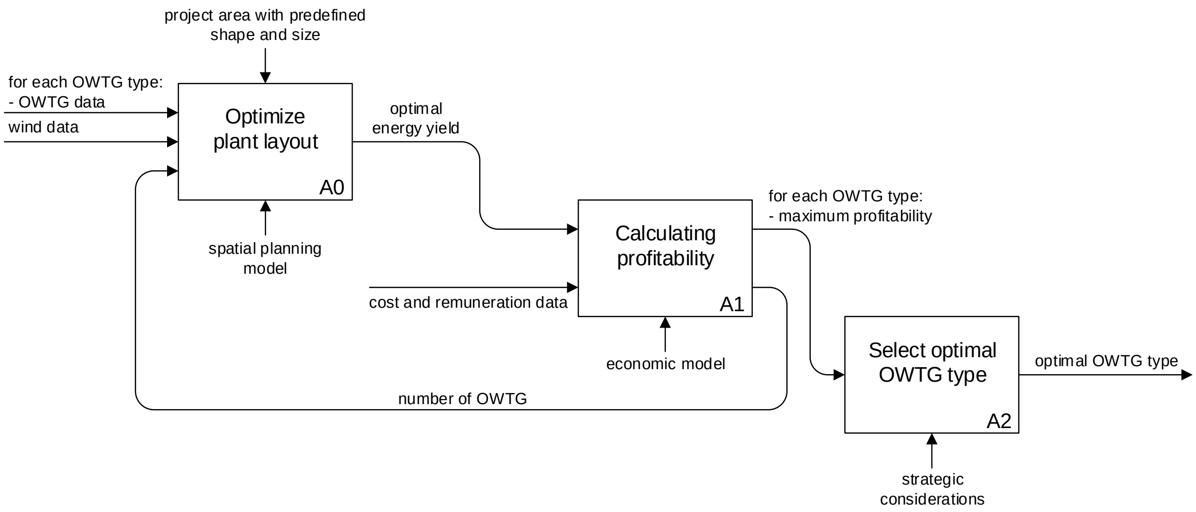

Figure 1-1: OWTG selection process.

2 Methodology

The OWTG selection process served as a reference for developing the research methodology of this article, which is shown in Figure 1-2. Instead of comparing different types of OWTGs from different vendors, the process was applied to OWTGs of different sizes. In order to obtain a clear picture and not being misled to jump to conclusions, the optimization loop was omitted. Instead of that the number of turbines was continuously increased within a range of installed capacity, which made it possible to trace the relations conditional on installed capacity. The methodology was also expanded by the LCOE model in order to evaluate the preferences of an energy policy planner. In the following sections spatial planning, profitability and LCOE model is described in detail.

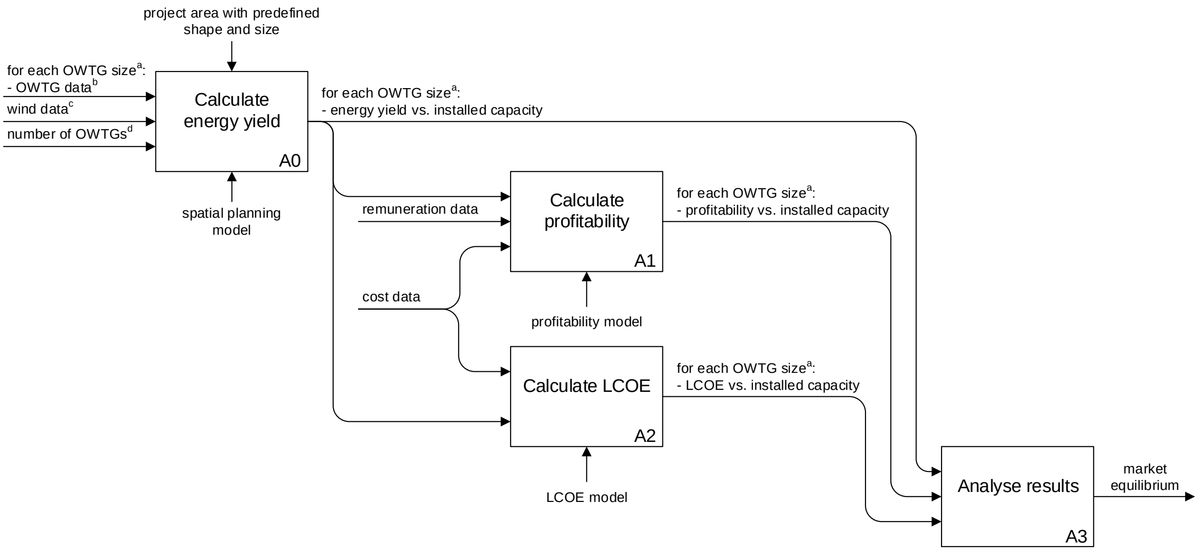

Figure 1-2: Methodology.
[a]OWTG sizes under investigation: 3 MW, 5 MW, 8 MW, 10 MW, 15 MW and 20 MW
[b]OWTG data: power curve, thrust curve, rated power, rotor diameter and hub height
[c]wind data: weibull distribution and probability for each direction sector (30°)
[d]number of turbines: varying between 300 – 600 MW installed capacity

2.1 Spatial planning model

An essential assumption for the spatial planning model was that the turbines are placed within an area of predefined shape and size. This is a reasonable approach, because the Federal

Maritime and Hydrographic Agency (BSH) [23], which is the main authority for approving OWFs in the German seas, gives in the first instance (1st release) only a basic permission to build a wind farm within a specified project area and guarantees that no other project will be approved within this area for a given period of time. Type, number and arrangement of turbines are allowed to be modified later on (2nd release), but the boundaries of the planning area are fixed. Hence the approach, which is similar to other countries, is to first do a general planning in order to secure the site and afterwards determine details such as the selection of an OWTG type.

Due to the wake effects and their significant impact on energy yield an algorithm was needed in order to find the optimal layout. Considering the number of academic literature that addresses this particular issue, whereof [22] provides an excellent and comprehensive review, reveals that this is currently a popular research topic. But this is already not only an issue on academic level. Wind farm planning software packages already contain optimization modules, which enable the users to optimize the plant layout using regular or random pattern regarding maximum energy capture [24,25] or even return on investment [26]. Considering this fact shows that the methodology presented in this article should be already state of the art for wind farm developers.

Although most papers propose algorithms using random patterns, the reality shows that symmetrical wind farm layouts are preferred especially in case of OWFs. [22] Since requirements concerning the safety and efficiency of vessel traffic in the German EEZ require that at least the outer line of turbines surrounding the OWF are placed in regular distance, it seemed to be obvious to place the turbines in a regular pattern for the whole OWF. [27] However, taking into account that this approach was applied to every OWTG size it seemed to be a minor issue.

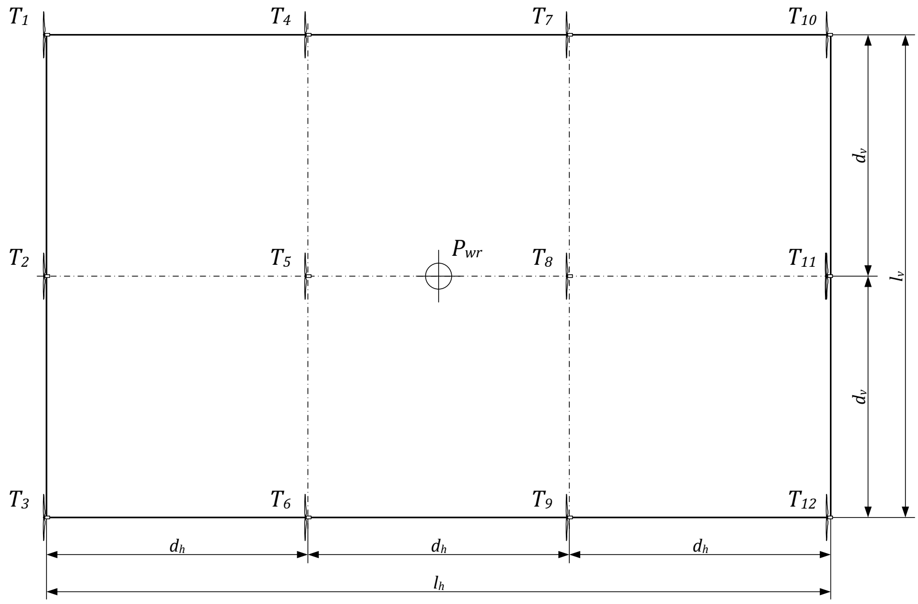

Figure 1-3: Example for placement of 12 (4 x 3 array) turbines.

The spatial planning model determined the layout using the number of horizontal and vertical turbines as an input. Figure 1-3 shows as an example how 12 turbines were placed. P_{wr} designates the point that has been chosen for the case study within the German North Sea and where wind resource data was available. This is also the centre of the planning area with a horizontal length l_h and a vertical length l_v. Since the horizontal distance d_h respectively vertical distance d_v between turbines must always be equal they result from dividing the corresponding length by the number of turbines minus one. In case of different array combinations (4 x 3, 3 x 4, etc.) which result in the same number of overall turbines, the one that generated the highest energy yield was used for the result analysis. As mentioned before the overall number of turbines was varied in a predefined interval of installed capacity. Finally, turbines were placed with a minimum distance of four rotor diameters, which is the limit of the wake model applied and beyond that commonly recommended due to high mechanical loads caused by turbulence effects. [28]

The output of the spatial planning model is the annual energy yield which can be obtained with the chosen wind farm pattern. The energy yield of one turbine Y_{WTG} within the farm per annum can be calculated using following equation:

$$Y_{WTG} = 8766 \cdot \sum_{\varphi} \rho(\varphi) \cdot \sum_{v_{hub}=v_{in}+0.5}^{v_{out}-0.5} f(v_{hwr}(v_{hub}), \varphi) \cdot P\big(v_{hub} - v_{def}(v_{hub}, \varphi)\big) \qquad (2)$$

where 8766 is the number of hours per year, φ the wind direction, $\rho(\varphi)$ the probability of occurrence for a specific wind direction, v_{hub} the wind speed at hub height, v_{in} the cut-in and v_{out} the cut-out wind speed of the wind turbine, $f(v_{hwr}(v_{hub}), \varphi)$ the probability of occurrence for a specific wind speed at a specific height $v_{hwr}(v_{hub})$ in a specific direction, $P(v_{hub})$ the power output for different wind speeds of the turbine and $v_{def}(v_{hub}, \varphi)$ the wind speed deficit caused by wake effects for a specific wind speed and direction. The formula is based on a methodology using wind speed bins recommended in the international standard IEC 61400-12-1 [29].

Due to the fact that the hub height of turbines increases with their size, the variability of the wind resource with height had to be included in this model. As stated in [30], using the power law instead of the stability dependent logarithmic law is suitable for a vertical extrapolation of the wind profiles for this application. The reason for that is that hub heights of OWTGs are in the Ekmand sublayer of the marine atmospheric boundary layer, which begins about 100 m above sea level, and there only a slight wind speed increase occurs. According to the international standard IEC 61400-3 [31], the height adaption using the power law can be calculated using following formula:

$$v_{hwr}(v_{hub}) = v_{hub} \cdot \left(\frac{z_{hwr}}{z_{hub}}\right)^{\alpha} \qquad (3)$$

where v_{hwr} designates the wind speed at the height where the wind resource is given, v_{hub} the wind speed at hub height of the turbine, z_{hwr} the height where the wind resource is given, z_{hub} the hub height of the turbine and α the power law exponent. This standard also recommends to use 0.14 for latter which should be suitable for offshore conditions. Considering the fact of only a slight wind speed increase in this heights and the results of measurement campaigns in this area (e.g. [32] claims an α of 0.10) this value seemed to be a quite conservative assumption.

For determining the wind speed deficit the wake model proposed by [33] and further developed by [34] was used, which is according to [22] the most widely accepted model by the wind industry and with regard to the objective of this article it seemed to be the right balance between computational effort and accuracy. For a single wake the wind speed deficit caused by a turbine in a distance x, can be calculate using the following equation:

$$v_{def\_single}(v_{hub}, \varphi) = v_{hub} \cdot \left(1 - \sqrt{1 - C_T(v_{hub})}\right) \cdot \left(\frac{d_R}{d_R + 2 \cdot k \cdot x}\right)^2 \cdot \frac{A_{shadow}}{A_R} \qquad (4)$$

where $C_T(v_{hub})$ is the thrust coefficient, d_R the rotor diameter, k the wake decay constant, x the distance between the turbines, A_{shadow} the shadowed area by the wake and A_R the rotor swept area. The wake decay constant k was assumed to be 0.04 which is a reasonable assumption for offshore wind farms. [35] In case of multiple interacting wakes [34] proposes to use following equation in order to calculate the resulting velocity deficit:

$$v_{def}(v_{hub}, \varphi) = \sqrt{\sum_{i=1}^{n} \left(v_{def\_single}(v_{hub}, \varphi)_i\right)^2} \qquad (5)$$

Hence for every wind turbine the energy yield was calculated including the wake effects of all other turbines. This required the consideration of geometric relations between the turbines subject to the wind direction. [17,36,37] provide good guidance how to calculate them.

Finally, the annual energy yield of the whole wind power plant can be calculated using

$$Y_{farm} = \eta \cdot \sum_{j=1}^{TN} Y_{WTG,j} \qquad (6)$$

where η is the efficiency of the plant and TN the number of turbines within the farm. A plant efficiency of 95 % was assumed, which includes losses due to unavailability, electrical transmission, power curve degradation, wind hysteresis, etc.

2.2 Economic models

2.2.1 Profitability model

As described before, it was assumed that OWF project developers try to maximize their profit and thus their only decision criteria for selecting an OWTG of a specific size is the resulting profitability of the project. As an indicator for profitability of the OWF the internal rate of return (IRR) was used, as it does not require assumptions on discount rates and it incorporates both costs and revenues. [38] This profitability parameter is calculated with a standard discounted cash flow model, which means that all cash flows – costs and revenues – are discounted over the lifetime of the plant to a base year. Using similar cash flow models of wind power plants (e.g. [37,39,40]) as basis the IRR can be derived by solving following equation:

$$0 = -C_{Dev} - P_R \cdot TN \cdot (c_{Inv} + c_{Dis}) + \sum_{t=1}^{T} \frac{Y_{farm} \cdot \left(r_t - c_{Op} \cdot \left(1 + i_{Op}\right)^{t-1}\right)}{(1 + IRR)^t} \qquad (7)$$

where C_{Dev} designates the onetime development costs, c_{Inv} the specific investment costs, c_{Dis} the specific dismantling costs, T the lifetime of the wind farm, r_t the remuneration per unit of energy for the respective year, c_{Op} the specific operation costs and i_{Op} the annual increase of the operation costs. Considering the facts that current offshore turbines are designed for a lifetime of 20 – 25 years, wind farm approvals in Germany expire after 25 years [41] and a construction and dismantling period of a few years, the assumption of 20 years for the lifetime T of the plant seemed reasonable and is also conform with literature. [38] For the sake of simplicity, it was assumed that all turbines are fully commissioned respectively dismantled at the same point in time.

The development costs comprise all expenditures for developing an OWF from scratch such as soil examination, environmental assessments and appraisals that have to be provided to the authorities during the approval process. All expenditures incurred during the construction and commissioning of the power plant are the investment costs, which are typically standardized to the base of kW or MW. Thus included are all costs for plant components (WTG, foundation, offshore substation, inner-array cabling), project management, logistics and others until the OWF is commissioned. Costs arising during operation such as maintenance, insurance and administrative costs are operation costs and are usually standardized to the unit of produced energy. Due to decreasing reliability of technical machines, it is reasonable to include an annual increase of operational expenditures. After the lifetime the plant has to be dismantled. All costs that arise in this phase are dismantling costs and are reduced by the residual value of the components. [42]

For the economic model it was assumed that the investment costs increase linearly with the installed capacity respectively operation costs with the energy produced, which influences the numerical results significantly. Therefore section 4.1 provides a critical reflection based on a comprehensive sensitivity analysis where the impacts of total cost variations and effects on costs such as economies of scale, cost development subject to upscaling, etc. are discussed in detail.

2.2.2 LCOE model

In order to be able to analyse the market equilibrium also from the perspective of an energy policy planner, the average lifetime LCOE was calculated. Adapting the formula defined by [43] to wind energy, LCOE can be calculated using following equation:

$$LCOE = \frac{C_{Dev} + P_R \cdot TN \cdot (c_{Inv} + c_{Dis}) + \sum_{t=1}^{N} \frac{Y_{farm} \cdot \left(c_{Op} \cdot (1 + i_{Op})^{t-1}\right)}{(1+r)^t}}{\sum_{t=1}^{N} \frac{Y_{farm}}{(1+r)^t}} \tag{8}$$

where r is the discount rate, which was assumed to be 10 %. [44]

2.3 Case study

2.3.1 Position and area

The position P_{wr} within the German EEZ for implementing the case study was chosen taking into account the areas that are approved for OWF projects by BSH and the availability of wind resource data. Figure 1-4 shows the chosen P_{wr} = 54° 28' 42.44'' N / 6° 19' 56.30'' E, which lies in an area with a water depth of 30 – 40 meters and is about 100 km away from shore. Considering the 25 wind farm projects in the North Sea that have been approved so far (status April 2013) by the BSH [41], an ordinary project area has a size of about 40 km², a shape with straight borders and comprises 80 wind turbines[3]. Hence a planning area with rectangular shape, vertical length of 5 km and horizontal width of 8 km was used for the case study.

[3] The reason for these characteristics of an ordinary project area might be that the BSH states that they have so far only projects approved that comprise maximally 80 wind turbines, because the impact of offshore wind farms on navigational safety and the marine environment has not yet been finally assessed.

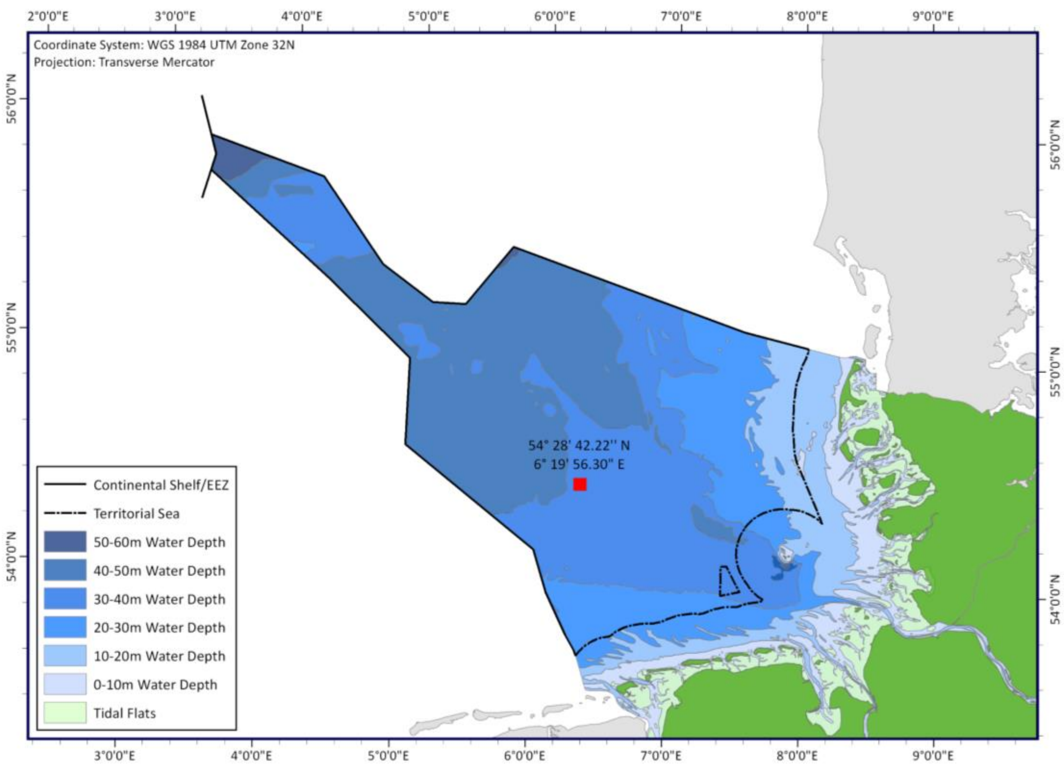

Figure 1-4: Position for case study (based on data provided by [45]).

2.3.2 Wind resource data

In order to obtain reasonable results, it is important to use wind data of high quality and not limiting their significance by simplification in the model such as using an average wind speed or only one wind direction. Basically, for calculating the energy yield of the wind farm including the wake effects a probability of occurrence for different wind speeds in the different directions is needed. It is common to provide the wind data as Weibull distribution which is defined as follows:

$$f(v,\varphi) = \frac{k(\varphi)}{c(\varphi)} \cdot \left(\frac{v}{c(\varphi)}\right)^{k(\varphi)-1} \cdot e^{-\left(\frac{v}{c(\varphi)}\right)^{k(\varphi)}} \tag{9}$$

where $k(\varphi)$ and $c(\varphi)$ represent the shape and scale parameter. For this analysis one point of the North Sea wind atlas developed by NORSEWInD research consortium [46] was used. They acquired, collated, quality controlled and analysed wind data from different measurement stations around the North Sea using different kinds of technologies with the aim to provide a reliable data basis for the wind industry. The wind resource data for the chosen point comprise $k(\varphi)$ and $c(\varphi)$ for 12 sectors of 30° width and the probability of occurrence for each wind direction $\rho(\varphi)$. As stated in [36], this is a good data basis for energy yield estimations. In order to generate results that make it possible to draw representative conclusions, a position with a quite good wind resource for the German EEZ was chosen. Figure 1-5 shows the wind rose at P_{wr}, where the total distribution parameters equal $c_{total} = 11.7\ m/s$ and $k_{total} = 2.12$.

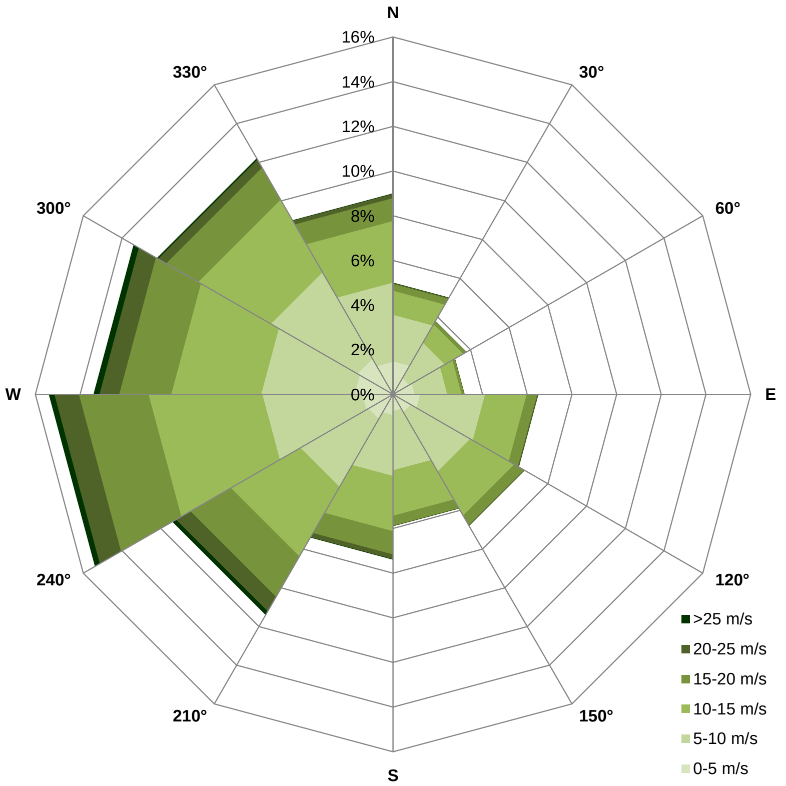

Figure 1-5: Wind rose at position 54° 28’ 42.44’’ N / 6° 19’ 56.30’’ E.

2.3.3 Wind turbine data

The methodology described above reveals that following data of every OWTG is needed: rated power, hub height, rotor diameter, power curve (power output vs. wind speed) and thrust curve (thrust coefficient vs. wind speed). This input data was defined based on specifications of current commercially available OWTGs ([47] provides a good overview), projections of the upscaling trend [48] and scientific concepts (e.g. [5–7]). Furthermore wind turbine data was determined very carefully in order to be as close as possible to reality, but also to have a clear difference between the different sizes. Table 1-1 provides the chosen dimensions of the different OWTG sizes.[4]

Rated power	3 MW	5 MW	8 MW	10 MW	15 MW	20 MW
Hub height	80 m	90 m	105 m	125 m	140 m	153 m
Rotor diameter	90 m	130 m	164 m	190 m	222 m	252 m

Table 1-1: OWTG dimensions.

The smallest size that was included in the analysis is 3 MW. As a reference for the data the Vestas V90-3.0MW [49] was used. This OWTG belongs to the last generation and has been deployed for example for the UK round 1 OWF projects at Kentish Flats and Barrow. [14] The data of the largest wind turbine were used from the UpWind project [6]. As a reference for OWTGs of the near future, data of the Vestas V164-8.0MW [50] and SeaTitan 10 MW [51] wind turbines were used. The dimensions of the 5 MW size, which is the current generation, and the 15 MW size were calculated using the others as basis and trendlines provided by [48]. The power curves were defined using the data of the turbines mentioned above and harmonizing them with each other to ensure that manufacturer specific deviations do not falsify the analysis. [52] presents a fast and efficient method of how rescaling of power curves can

[4] It has to be commented that the results of this analysis do not reflect the relative performance of the turbines used as a reference, because the power curves and thrust curve were significantly modified.

be done based on equation (1). Figure 1-6 shows the applied power curves. The same thrust curve, cut-in wind speed (4 m/s) and cut-out wind speed (25 m/s) were used for all turbines.

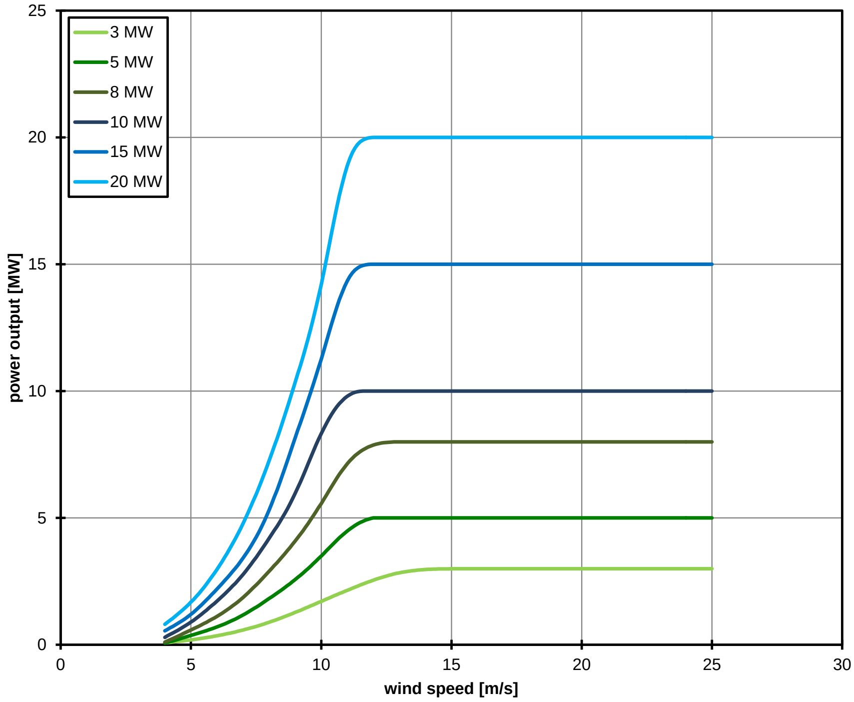

Figure 1-6: Power curves.

2.3.4 Cost assumptions

There are several sources available where the cost components of OWFs are assessed and analysed (e.g. [39,53]). For the model developed in this paper it was more important that the relation of the cost components relative to each other is reasonable than their individual level. This is why all values were used from one source, because cost data vary significantly between different projects and in that way the same data basis is ensured. Hence cost data of the German offshore market provided by [42] were used for the analysis (see Table 1-2).

C_{Dev}	35 EUR million
c_{Inv}	3.6 EUR million per MW
c_{Op}	25.5 EUR per MWh
i_{Op}	2.0 % per year
c_{Dis}	0.2 EUR million per MW

Table 1-2: Overview of cost assumptions.

2.3.5 Remuneration assumptions

According to the renewable energy law (EEG) in Germany [54], an operator of an OWF can choose between three remuneration options (see Table 1-3). For this model it was assumed that 16 years after commissioning the energy is remunerated with a tariff of 150 EUR/MWh, which corresponds to the standard option plus an extension period of four years (36 m water depth and 100 km distance to shore). Subsequently it was assumed that the energy is traded for the remaining four years. The average market price in this period was calculated using 50 EUR/MWh as basis for the year of commissioning and adding an escalation of 2% every year.

	Initial period		Extension period	Remaining period
Trading			market price	
Standard	150 EUR/MWh 12 years	+	150 EUR/MWh 0.5 months for every nautical mile beyond 12 nautical miles to shore	35 EUR/MWh
Compression	190 EUR/MWh 8 years	+	1.7 months for every meter beyond 20 m water depth	

Table 1-3: Remuneration scheme (commissioning before 1.1.2018 assumed).

3 Results

The model was evaluated for an OWF with an installed capacity between 300 and 600 MW, which seemed to be reasonable for the selected case study parameters. In addition to the economic parameters IRR and LCOE the energy yield was calculated in order to determine also the behaviour of the physical basis. Placing turbines with a reasonable proportion between horizontal and vertical quantity and within the installed capacity limits revealed an almost linear relationship between installed capacity and energy yield (see Figure 1-7).

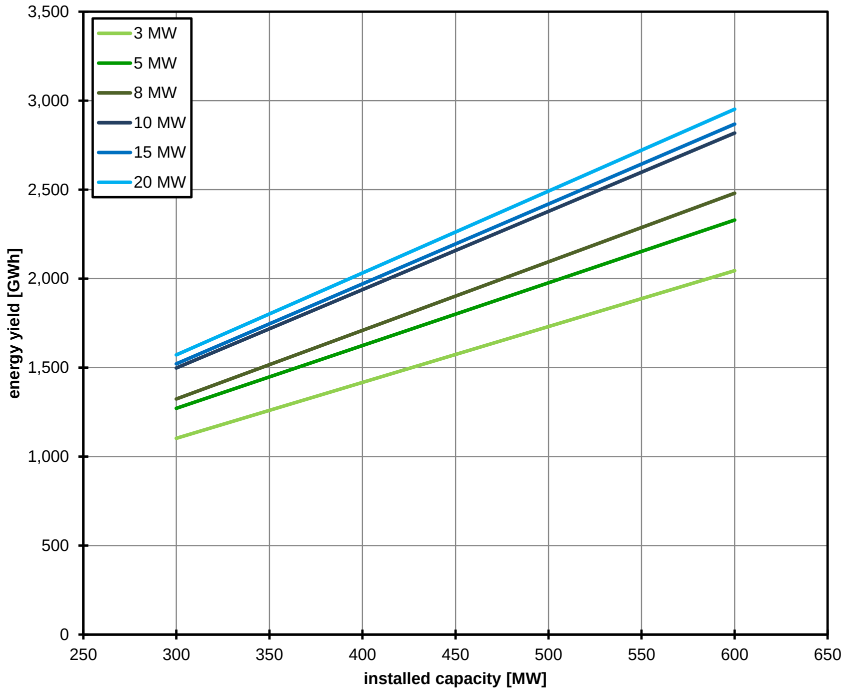

Figure 1-7: Energy yield vs. installed capacity.

Since the economic parameters highly depend on the energy yield they also follow an almost linear trend conditional on the installed capacity. Therefore Table 1-4 provides the results in the form of linear regression factors including the coefficient of determination.

In order to be able to derive conclusions Figure 1-8 shows the mean relative deviations subject to the OWTG size using the 10 MW turbine as a benchmark.

OWTG size	Energy yield			IRR			LCOE		
MW	MWh		R^2	%		R^2	EUR/MWh		R^2
	m	b		m	b		m	b	
3	3139.50	161,281	0.9967	-2.73E-05	9.28%	0.8219	2.37E-02	148.23	0.7722
5	3523.19	214,794	0.9987	-3.77E-05	11.87%	0.9343	2.61E-02	130.80	0.9344
8	3854.41	166,978	0.9978	-2.67E-05	12.27%	0.7890	1.70E-02	128.92	0.7887
10	4403.55	176,287	0.9990	-2.75E-05	14.53%	0.7997	1.40E-02	117.54	0.7809
15	4489.80	174,544	0.9996	-2.72E-05	14.84%	0.8422	1.35E-02	116.17	0.8354
20	4536.84	217,894	0.9995	-2.48E-05	15.32%	0.9080	1.19E-02	114.01	0.9051

- valid within range between 300 and 600 MW installed capacity
- $y = m \cdot P_R \cdot TN + b$ where y is the energy yield / IRR / LCOE
- linear least squares regression applied

Table 1-4: Relationship between energy yield / IRR / LCOE and OWTG size specified in form of linear regression factors.

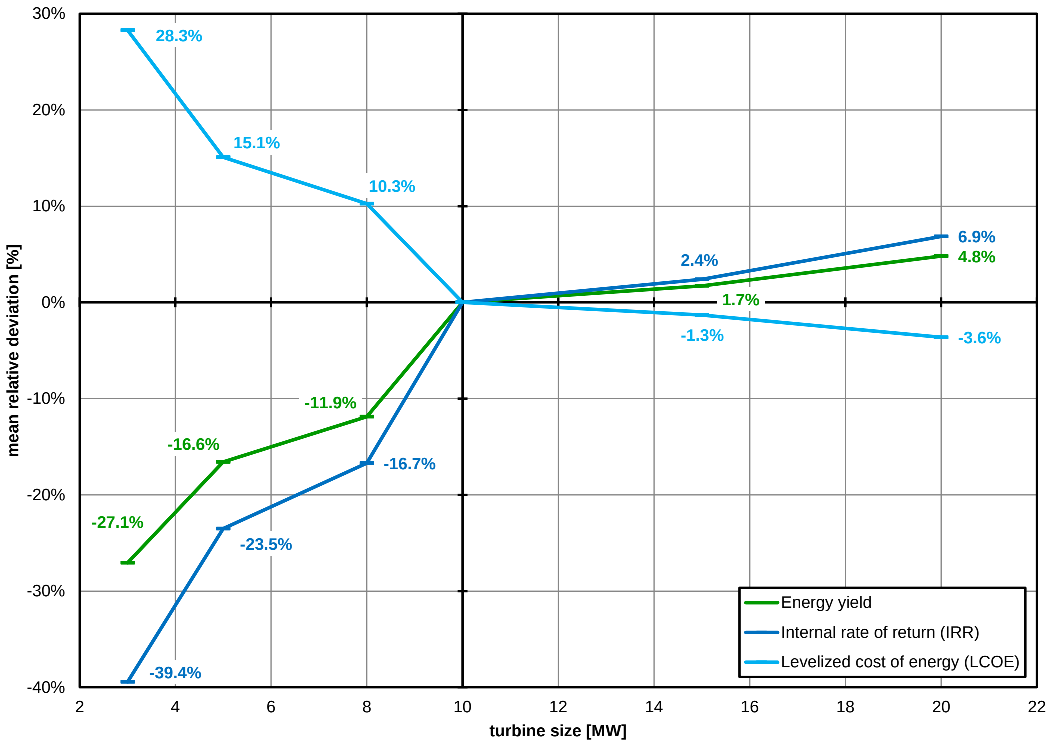

Figure 1-8: Mean relative deviations of energy yield / IRR / LCOE subject to OWTG size using 10 MW as a benchmark.

4 Discussion and analysis of results

The results apparently indicate a market equilibrium for OWTGs with a size of 10 MW. The fact that doubling the size from 10 MW to 20 MW, which entails substantial technical challenges, gains only a minor increase in energy yield and thus also in IRR, which is the customers' key figure for a purchase decision, suggests that the incentive for wind turbine manufacturers to invest in the development of 20 MW turbines at least for the German offshore wind market is insufficient. The results indicate that the potential increase of the energy yield and the significantly decreasing potential sales volume may not compensate the effort for developing larger OWTGs, setting up new manufacturing facilities and elaborating new installation and service concepts. Cost reductions that can be obtained due to increasing reliability and standardization may have a similar or even higher cost-benefit effect. [44,55] Apart from that the trend of the LCOE subject to OWTG size questions governmental subsidies, which support the development of OWTGs beyond the size of 10 MW, since this does not lead to the intended significant cost degression. The reason for a flattening of the energy yield and as a consequence also of the IRR and LCOE with increasing OWTG size is simply the limited available wind resource. Something similar was already reported in [56], where the results reveal that higher yield from larger OWTGs far away from shore do not compensate for the increased costs compared to smaller OWTGs near the coast.

4.1 Critical reflection and sensitivity analysis

Admittedly, the analysis is based on several assumptions that were needed to anticipate the future development of OWTGs. Therefore this section provides a critical reflection of the input parameters in order to prove if the methodology presented generated representative results. It has to be pointed out that the aim of this article was to show that there is an indication for a market equilibrium. Especially the analysis of the economic parameters IRR and LCOE was not aiming at providing an exact numerical projection of these parameters. The intention was to show that these key figures, which are the basis for a purchase decision of the wind turbine manufacturers' customers respectively the basis for decision-making for energy policy planners, are also flattening with increasing OWTG size similar to the energy yield. Thus the economic analysis presented before should only give evidence with regard to future market behaviour. The critical discussion in the following is based on a comprehensive sensitivity analysis (see Supplementary Notes for detailed results).

For the sake of simplicity and considering the fact that all result parameter functions are almost linear and parallel subject to the installed capacity it is useful to discuss only the relative and absolute effect of each sensitivity case. Relative effect means that the average relative distance between the result function for a specific wind turbine size and the 10 MW benchmark either increases or decreases. Or in other words the graphs shown in Figure 1-7 are either expanded or contracted. In contrast to that, absolute effect means that all result functions are shifted either to lower or higher values without changing their relative distance to the 10 MW benchmark. Figure 1-9 provides a visualisation of these effects. With regard to the aim of this article only the relative effect of an increased distance (expansion) to the 10 MW benchmark would oppose the conclusion of a 10 MW market equilibrium.

The main input parameter with regard to the impact on energy yield is clearly the wind resource. Table 1-5 provides an overview of the effects caused by the associated sensitivity cases. For the case study only one position of the NORSEWInD atlas [46] was used, which questions how representative the selected wind resource for the German EEZ is. Analysing the NORSEWInD atlas within the German EEZ and considering only areas which are allocated for offshore wind reveals that the minimum ($c_{total} = 11.5\, m/s$ / $k_{total} = 2.12$) and maximum ($c_{total} = 11.8\, m/s$ / $k_{total} = 2.12$) wind resource do not significantly deviate from the one used for the analysis. Thus basing the analysis on these two wind resources leads subsequently only to minor deviations and mainly to a shift to lower respectively higher values.

Another critical aspect of the analysis is the height adaption using the power law with an exponent of 0.14, which is, as discussed before, a quite conservative assumption. The result using a lower power law exponent ($\alpha = 0.00$) is obvious: lowering the power law exponent leads to the relative effect of contraction, because the assumption causes that the wind resource is the same for every turbine size and thus larger turbines with higher hub height do not have a higher wind resource available. Moreover, this admittedly extreme sensitivity case exhibits that the losses due to wake effects would be also higher for larger OWTGs resulting in less energy yield for the same installed capacity compared to the 10 MW benchmark.

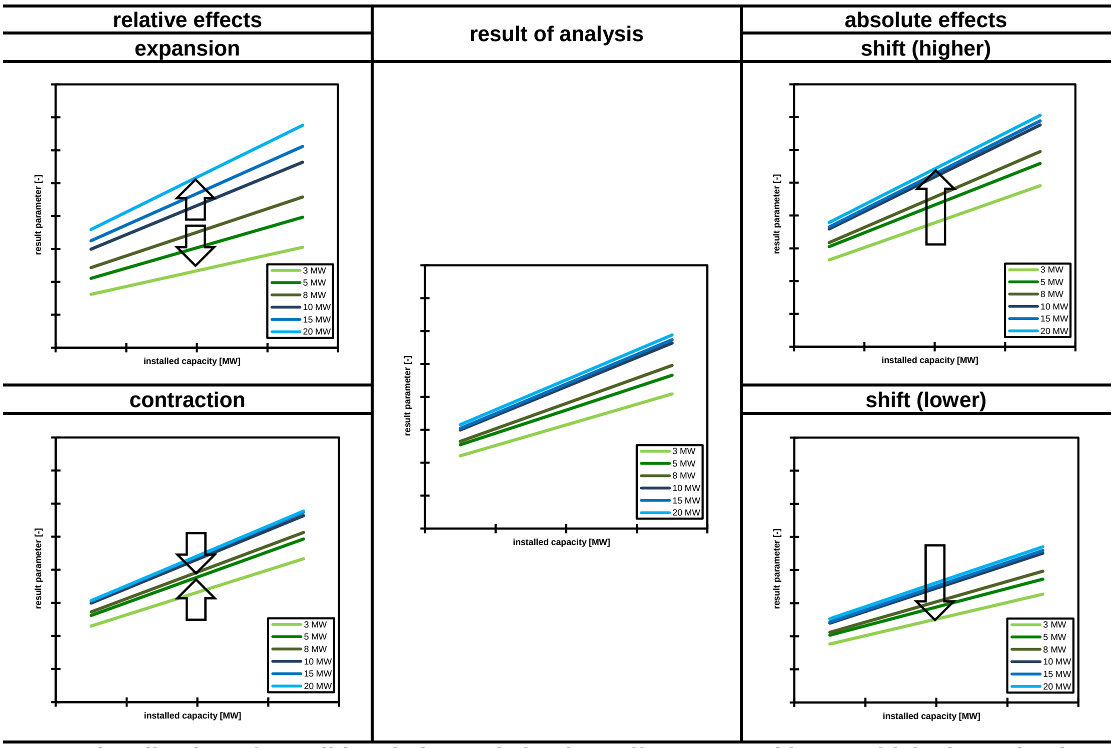

Figure 1-9: Visualisation of possible relative and absolute effects caused by sensitivity investigations.

Considering these sensitivity cases investigating the effects caused by changes of the input wind resource shows that although they have an impact on the numerical result, they prove that the article’s statement regarding the presence of a market equilibrium is robust. Apart from that, also wind turbine data and the wake model could have influenced the energy yield. Possible deviations caused by those inputs can be ruled out since the data for the 3 MW, 8 MW, 10 MW and 20 MW size stem from reliable sources and the wake model was verified using professional wind energy assessment software.

Sensitivity case	Energy yield	
	relative effect	absolute effect
higher wind resource	slight contraction	shift (higher)
lower wind resource	slight expansion	shift (lower)
lower power law exponent	contraction	-

Table 1-5: Sensitivity effects due to changes in wind resource assumptions.

But apart from the assumptions used for calculating the energy yield, also the effects of varying cost inputs should be discussed in more detail (see Table 1-6). First of all the level of costs are worthy of discussion, because for example the specific investment costs depend significantly on distance to shore and water depth. [57] Apart from that substantial cost reductions are intended in the near future in order to make electricity from offshore wind more competitive. [2,3] However cost may develop in future, when assuming that all sizes experience the same negative or positive cost trend, the effect on IRR and LCOE is only absolute. This effect is the same for any change in feed-in remuneration scheme as long as electricity from larger OWTGs is not remunerated differently than that from smaller OWTGs. Since costs and remuneration determine profitability and therefore investment decisions any absolute change would only influence the sales volume for OWTGs, but not affect the purchase decision regarding OWTG size. Thus the conclusion of the presence of a market equilibrium is independent of the level of cost or feed-in remuneration.

Sensitivity case	Internal rate of return		Levelized cost of energy	
	relative effect	absolute effect	relative effect	absolute effect
Cost reduction	slight concentration	shift (higher)	-	shift (lower)
Cost increase	slight expansion	shift (lower)	-	shift (higher)
Larger comparatively less expensive than smaller	expansion	-	expansion	-
Smaller comparatively less expensive than larger	concentration	-	concentration	-

Table 1-6: Sensitivity effects due to changes in cost assumptions.

Another point of criticism might be the assumption that no economies of scale occur, which seems to be unrealistic and the resulting linear functions for IRR and LCOE implausible. First of all, it has to be commented that the survey done by [58] clearly shows that economies of scale for OWFs do not occur so far. However, the presence of economies of scale may again have an impact on the numerical results of this analysis, but it is not reasonable that this would change the conclusion. The reason for that is the simple fact that economies of scale for smaller OWTGs will always occur before they do for larger ones, because for an OWF with the same installed capacity always less larger than smaller turbines are needed. Hence considering this effect in a chronological view, it rather promotes the theory of a market equilibrium, because wind turbine manufacturers, who are facing the decision of either developing a larger OWTG or continuing to exploit economies of scale with the current generation, are aware that economies of scale for the larger OWTGs take only effect again after selling large quantities, which is more difficult since they can only sell less OWTGs for the same OWF size. [59] Even it is assumed that economies of scale become effective in the same quantity range this would only change the shape of the graph, but not have a relative effect on IRR or LCOE.

More interesting is the question how cost will develop with increasing size. Would larger wind turbines be comparatively less (more) expensive than smaller, an expansion (contraction) of the graphs would be the consequence, which would disprove the statement of this article. But investigations about costs in relation to upscaling clearly reveal a disproportional increase of costs with size due to the impact on weight and loads. [7] A good example is [8], where after a comprehensive analysis is concluded that turbine sizes lower than 10 MW will be optimal due to the exponential increase of cost subject to size. In conclusion, although the analysis presented in this article is based on several assumptions, the sensitivity analysis showed that the theory of a market equilibrium for 10 MW OWTGs is robust.

4.2 Managerial implications

In case of the presence of a market equilibrium for OWTGs the conclusion for stakeholders in the offshore wind industry is obvious. Focusing instantaneously on developing 10 MW OWTGs and placing them onto the German offshore wind market, would promise wind turbine manufacturers a sustainable competitiveness. This would be also applicable for the supplying industry as for example foundation and ship vendors that are forced to adapt their products to the size of OWTGs. Interestingly, the analysis also revealed a significant increase in efficiency for installing 5 MW turbines instead of 3 MW respectively 10 MW instead of 8 MW and only a minor increase between 5 MW and 8 MW OWTGs. This would be an indication for the 8 MW size being only an intermediate technology level.

For energy policy planners and governmental decision makers the market equilibrium would suggest that it should be preferred to grant subsidies to research projects that investigate how it is possible to improve the maturity of the technology instead of investing in projects that investigate OWTGs of a size that might be never reasonable. For example fostering technology transfer from other successful industries such as oil & gas, which have considerable experience in offshore operations, might gain more efficiency in order to significantly reduce the cost of electricity generation from offshore wind. [60] It has to be mentioned that the cumulative discounted operating costs over the whole life cycle account for 35 – 45 % of the overall project costs. Considering also the cost reduction potentials for operation & maintenance costs of about 12 % [61] resp. 14 % [62], which could decrease the overall OWF costs of up to 7.8 % [2], suggests that supporting a reduction of operating costs is as important as research projects that aim for lowering the initial investment costs.

OWTG size	Maximum number of turbines[a]	Maximum installed capacity[a]	Average installed capacity per unit area	Average annual energy yield per unit area
MW	-	MW	MW/km^2	MWh/km^2
3	182	546	13.7	46.9
5	90	450	11.3	45.0
8	64	512	12.8	53.5
10	49	490	12.3	58.4
15	36	540	13.5	65.0
20	25	500	12.5	62.3

[a]within 40 km^2 assuming minimum horizontal distance of seven and vertical four rotor diameters

Table 1-7: Average installed capacity and energy yield per unit area.

Moreover, the results presented in this article also enable to estimate average installed capacity respectively annual energy yield per unit area and their relation to OTWG size (see Table 1-7). Applying the common recommendation for wind farm layout design presented in [28] to all OWTG sizes reveals that the average installed capacity per unit area remains nearly constant, which does not surprise considering the geometric relations. Although an average value of 12.5 MW/km^2 seems to be quite high ([63] reports 9 MW/km^2 respectively 7 MW/km^2 for UK round 1 rsp. 2 OWFs), the fact that it is independent of the OWTG size contradicts investigations about the future trend (e.g. [64]) that claim an increase of this value with technological development. Apart from that, this information is of particular interest for transmission system operators and offshore substation suppliers since it enables to estimate the maximum capacities expected from sea areas. It also allows the conclusion that the development of standard sizes is reasonable, which would help to reduce costs. Finally the annual energy yield per unit area gives advice to energy policy planners since it answers the question what maximum energy extraction can be expected from sea areas in the German EEZ.

5 Conclusion

This article refers to the current issues of the offshore wind industry with the tight market conditions due to the pressure to continuously place larger OWTGs onto the market. A model was developed with the objective to identify a market equilibrium for OWTGs. This was identified investigating the trend of growing OWTGs from an OWF project developer's point of view, which reflects the demand side of the market, and from the point of view of an energy policy planner. In order to be able to generate reasonable conclusions, the model was applied to a case study wind farm in the German EEZ. Finally, a sensitivity analysis verified the robustness of the article's statement.

The results indicate a market equilibrium for 10 MW OWTGs due to the limited available wind resource. This is highly interesting for stakeholders in the offshore wind industry and allows individual conclusions. The strategic focus on this size might promise OWTG manufacturers and the supplying industry a sustainable competitiveness. A governmental planner might be better advised to support research projects with funding that aim for improving the 10 MW range instead of the development of OWTGs that do not gain a significant yield and efficiency increase. Finally, the analysis gives information about how much energy yield and installed capacity can be expected from German North Sea areas.

Although the German EEZ is one of the most promising markets for offshore wind in Europe, it would be interesting to investigate the OWTG market equilibrium also for other regions in the world. This could be done using the methodology presented in this article, if necessary adapting it to the legal framework for OWFs in the respective country and applying the respective local wind resource. However, the wind resource used is quite good and experiences reveal that already these conditions are challenging the reliability of currently used technology far away from shore.

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PUBLICATION 2

Evaluating capital and operating cost efficiency of offshore wind farms: A DEA approach

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Abbreviations: Banker-Charnes-Cooper (BCC); capital expenditures (CAPEX); Charnes-Cooper-Rhodes (CCR); Data Envelopment Analysis (DEA); operating expenditures (OPEX); offshore wind farm (OWF); wind energy converter (WEC)

1 Introduction

More than 20 years after the first offshore wind farm, Vindeby, went operational, the expansion of offshore wind is in full progress, resulting in a cumulative installed capacity of 6.6 GW in the European seas in 2013. [1] High wind speeds at sea promising a high energy yield and extensive areas available for large-scale projects without negative effects on residents, such as visual impact, noise production and shadow casting, make offshore wind increasingly attractive also compared to its onshore counterpart, resulting in ambitious projections of 40 GW installed capacity in 2020. [2] Conversely, harsh environmental conditions, increased loadings and great distances to shore lead to high costs, which necessitate governmental support to compensate for the lack of competitiveness. [3] Therefore, cost reduction constitutes the main challenge that will be faced in the offshore wind industry in the coming years, which is reflected by the target to reduce costs by up to 39 % through 2020 [4,5], aiming at a levelised cost of energy of 9 ct/kWh (status 2012: 11-18 ct/kWh) [6]. This situation implies that cost evaluation is a significant issue in offshore wind for tracking changes and identifying cost-reduction potentials. Actual cost analyses often suffer from imprecision with regard to handling influencing parameters and poor databases due to stakeholders' restrictive non-disclosure policies and the rapid increase in the number and extent of projects in recent years. This study has overcome these issues by utilising a reliable database and by applying Data Envelopment Analysis (DEA) to offshore wind farms (OWF). This operations research method enables the evaluation of the relative efficiency of multi-input multi-output entities, so-called Decision Making Units (DMU), and the determination of a best-practice frontier.

The idea of developing this model originated from the issue of ensuring comparability within the database when evaluating the costs of OWFs. In offshore wind cost assessments, it is common to use specific capital costs (EUR/kW) to estimate and compare costs or analyse trends (e.g., [7], Exhibit 3.2 [5], Fig. 8.3 [8]). At first glance, using average cost values that are normalised to the installed capacity appear to be an effective approach because it has been used for onshore wind power plants for decades. However, considering the database on which such assessments are grounded—consisting of, for example, the Middelgrunden OWF, commissioned in 2001 with an installed capacity of 40 MW, located in shallow waters measuring 5.5 m deep and a distance to shore of 3.5 km [9], and the Greater Gabbard OWF, commissioned in 2012 with the specifics of 504 MW / 29 m / 23 km [10]—it is highly questionable whether results based on specific capital costs are significant. Water depth and distance to shore are two of the main cost drivers in offshore wind [11] because they reflect the level of environmental loads to which an OWF is exposed. [12] Hence, these main specifics have a significant impact on cost figures and must be carefully considered. These properties can be properly examined by, for example, regression analysis, as presented in [13]; engineering correlations, as described in [14]; or using a practical approach, as conducted in [15], in which—based on a case study—scale factors that indicate the variation in cost as a function of water depth and distance to shore were calculated. However, all of these approaches appear to be non-optimal because they do not incorporate all of the specifics and available data at once. Herein lies the main advantage of DEA because it enables modelling every OWF as an entity with the specifics as its inputs (outputs). This type of holistic approach might be one reason why this method has gained great popularity in energy and environmental modelling in recent years (see [16] for a review), and there are numerous articles that have used DEA to assess the performance of power plants (see [17] for a survey of relative performance evaluations of conventional power plants applying DEA). However, the literature concerning the investigation of the efficiency of wind farms using this method is scarce (see

[18–21] for onshore wind farms). Indeed, this is the first article, to the best of the author's knowledge, in which DEA is applied to OWFs.

The overall objective of this study was, on the one hand, to develop a useful methodology for evaluating how efficiently costs are used for developing, installing and operating OWFs and, on the other hand, to use the methodology as basis for an in-depth cost analysis applying data from already implemented OWFs. Thus, this study closes the aforementioned gap in the literature because it provides stakeholders a reasonable method for reviewing the relative performance of OWFs in terms of costs and reliable figures as a benchmark. It seemed reasonable to divide the analysis into a static model for evaluating capital cost efficiency, which refers to all one-time expenditures associated with development and installation until the takeover of an OWF, and a dynamic model for investigating operating cost efficiency, which refers to all expenditures specified on a yearly basis occurring after the point of takeover until the decommissioning of an OWF. [11] The in-depth cost analysis was aimed at investigating several interesting aspects associated with offshore wind costs using the previously developed model and applying some extensions of DEA within the context of a case study. Thus, in addition to calculating the relative efficiencies by DEA, sources of inefficiency were assessed. Moreover, DEA allows for the identification of best practices, which is the basis for calculating cost efficiency frontiers. Hence, another objective was to provide a chart similar to that presented in [15], which has also been used in other publications (e.g., [22,23]) and shows cost as a function of the main specifics of OWFs. This was implemented through sensitivity analysis with DEA and showed what level of capital (operating) costs would be optimal relative to those of other OWFs already implemented. Finally, the determination of relative cost efficiencies allowed for the analysis of their relationship to other factors, such as year of commissioning or installed capacity, which in turn provided information about the effects of learning and economies of scale. To date, the investigation of these effects—for example, as completed in [12,24,25]—have been based on specific costs, which again calls into question the results due to the previously discussed lack of comparability. As stated in [25], the understanding of and correction for the two cost-increasing effects of water depth and distance to shore could improve learning curve analyses for OWFs. Thus, the methodology presented in the following also offers a reliable method for interpreting cost development and verifying whether and to what extent cost reductions take place.

An important principle for the analyses presented in this article—which posed, at the same time, the most formidable challenge—was the requirement of using input data of the highest possible quality. It is understandable that companies do not want to provide commercially sensitive performance data, but the offshore wind industry appears to be extraordinarily secretive. The reason for this behaviour might be the fact that this industry is quite young and still rapidly developing. Withholding information about experiences that were possibly quite costly promises market participants the maintenance of competitive advantages and raises barriers to entry. The capital cost estimation completed in [8] shows which typical sources are used for gathering cost data. Sources originate either from offshore wind farm owners' websites or reports, in which it is difficult to detect whether the figures were massaged, or from online databases, such as [26], and reports of consulting companies, where the original source is often not disclosed and it is not clear how data were processed (e.g., deflation). It is clear that these sources are not sufficiently reliable to generate significant results. Therefore, all cost data used for the investigation originate directly from annual financial statements and are verified using only information from owners' websites and reports, which is possible because offshore wind projects are usually arranged through Special Purpose Vehicle (SPV) companies—separate legal entities that are used to isolate the owner from financial risks. [27,28] The annual reports of these SPVs are officially deposited and accessible at the respective register of companies. [29–34] This database is unique and ensures the significance and usefulness of the article's results for stakeholders of the offshore wind industry. The names and cost data of individual OWFs' SPVs are intentionally not quoted because the intention of this publication is to provide a reliable scientific analysis of offshore wind costs and not to compromise anybody on any account.

The next section presents how capital and operating cost efficiency were modelled using DEA. Section 3 provides a description of the input data for the case study and their preparation. The results of the analysis are presented in section 4 and subsequently discussed in section 5.

2 Modelling

Before the DMUs are characterised and the mathematical model is explained, it must be noted that the methodology presented in the following represents the result of a comprehensive analysis in which many different configurations of inputs (outputs) and modifications of DEA were investigated with respect to their reasonableness and applicability to reality.

2.1 Characterisation of DMUs

In the course of researching the literature for this article, it was particularly noticeable that most authors attach importance to a detailed description of the chosen DEA model, whereas there is often a lack of reasoning why specific input (output) parameters were selected, why specific parameters were used as input rather than as output or vice versa and how they are related to the efficiency of the DMU. It is clear that the selection of parameters and how they are included in the model are as significant as the model itself with regard to the quality of the results. Thus, a detailed description of the selected DMUs and how the selected parameters influence the DMU efficiency is provided in the following.

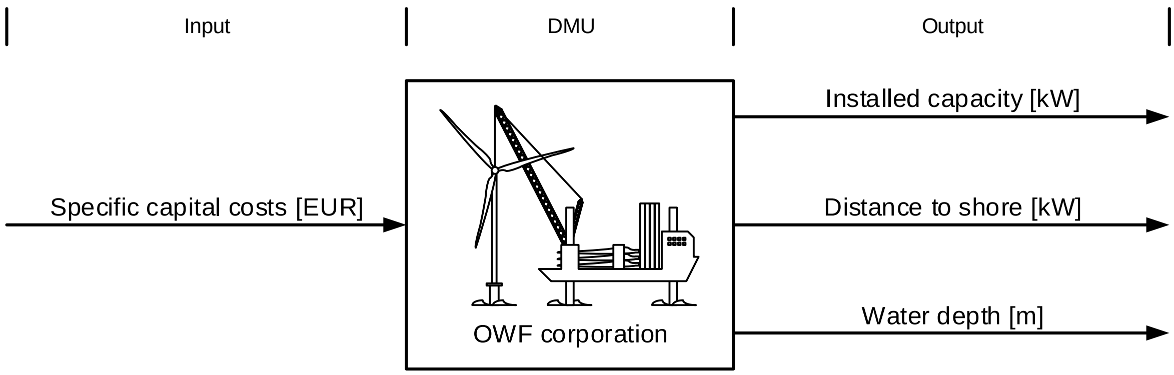

Figure 2-1: Model for capital cost efficiency analysis.

2.1.1 Capital cost efficiency

In this case, the DMU is the entity that develops and installs the OWF. As shown in Figure 2-1, this entity transforms the only input specific capital costs into an OWF of a specific size (= installed capacity) for a specific distance to shore and water depth. As mentioned previously, capital costs (also referred to as capital expenditures or CAPEX) are defined as all expenditures that occur until the OWF is commissioned, meaning that they comprise all investments for OWF development, such as soil examinations, environmental assessments and appraisals for certification as well as all investments for OWF deployment, such as the purchase and installation of components and project management. [13] Installed capacity is often used as an indicator for the size of a wind power plant. It is the product of the wind energy converters' (WEC) rated power, defining the level of power for which the turbine and its components are designed, and the number of turbines of the plant. Distance to shore and water depth were included because they are the main drivers for capital costs. Thus, the theoretical production function can be formulated: the greater the specific capital costs invested for deploying the OWF, the larger (installed capacity) it will become, the farther off shore the OWF will be situated and the greater the water depth of the OWF site will be.

2.1.2 Operating cost efficiency

For the operating cost efficiency analysis, the DMU is the entity that is responsible for the OWF during its operational phase, which might be the operation and maintenance department of an energy utility or an external service provider. In the following, this DMU is referred to as the service agent. To be able to select parameters that determine the performance of an offshore wind service agent, it is necessary to understand what affects the efficiency of a WEC, which is discussed in the following. The author of [35] provides a good visualisation of a WEC's efficiency, plotting the energy density as a function of wind speed. Figure 2-2 shows an adapted version of this graph using a generic 5 MW WEC as the basis and depicting the annual energy yield per rotor swept area as a function of wind speed. The main input for a WEC is, of course, the wind or, more specifically, the kinetic energy content of the wind. This kinetic energy is given exogenously by nature and can be calculated using the following equation:

$$E_{kin\_wind} = \frac{1}{2} \cdot A \cdot \rho \cdot v^3 \cdot t \tag{1}$$

where A designates the swept area of the rotor, ρ is the air density, v is the wind speed and t is time. According to Betz's momentum theory, there exists a physical limit for the amount of mechanical energy that can be extracted from a free-stream airflow by an energy converter under ideal conditions, which is 16/27 = 59.3 % of E_{kin_wind}. Whereas this loss cannot be avoided, the next sectional area shown in Figure 2-2 represents the aerodynamic losses that occur because a real wind rotor has an efficiency below the theoretical limit. Due to economic and technological constraints, a WEC is designed for a specific rated power, which causes another major loss. Finally, the remaining area, after subtracting mechanical and electrical losses, represents the gross annual energy yield. This yield can be calculated using the power curve of the WEC and the wind resource at the wind farm site. Thus far, all losses are a result of physical constraints or the wind turbine's design.

The last portion indicates the loss due to the WEC being unavailable, which is in principle the only loss that can be influenced by the service agent. This is why availability is a common performance metric for the operation and maintenance of wind power plants. [36] Unfortunately, the distinction between time-based and production-based (also referred to as energy- or yield-based) availability is often overlooked, although the difference between the two is significant for evaluating operational performance. One reason for this oversight might be that an international standard for defining the latter is still under development. [37] According to IEC/TS 61400-26-1 [38], time-based availability is defined as the "fraction of a given operating period in which a wind turbine generating system is performing its intended services within the design specification". Therefore, 95 % time-based availability means that the WEC does not perform its intended service (i.e., it is not able to convert energy due to malfunction, maintenance, etc., for 5 % of the operating period). However, this figure is not actually tantamount to an energy loss of 5 % because it depends on the prevailing wind speed during the downtime of the turbine. Because the operator is remunerated for the energy fed into the grid, the time-based availability is only an indicator but not an optimal performance metric. [39–41] provide empirical studies and reviews of this topic.

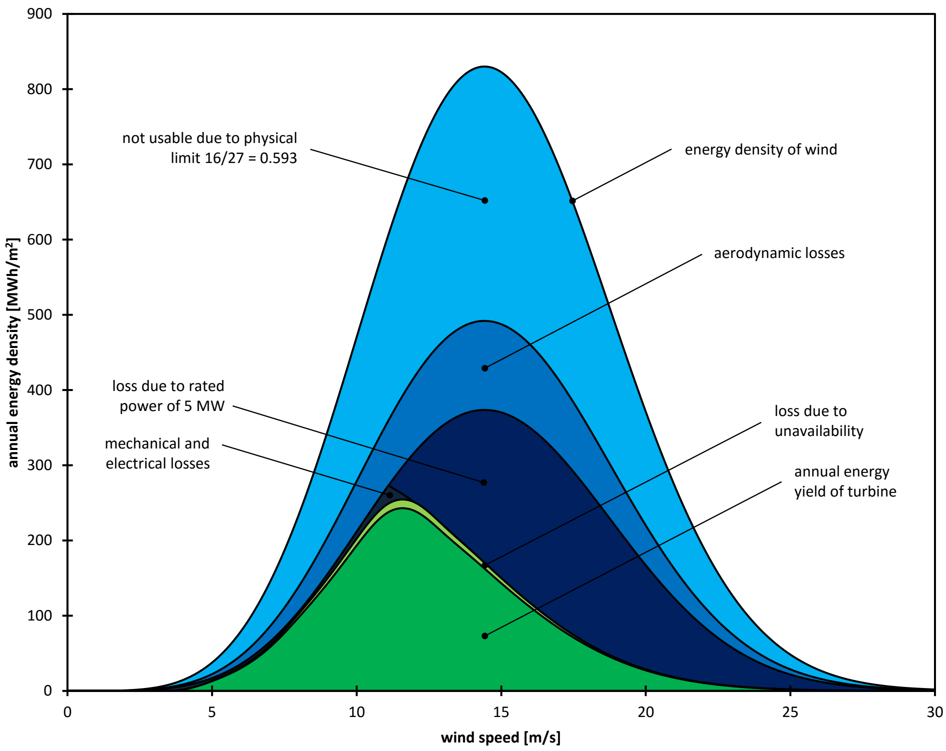

Figure 2-2: Efficiency of a wind turbine. (cf. [35]; p.525)

The amount of energy lost during the period of turbine unavailability depends on the technical quality of the wind turbine and the performance of the service agent. The quality of a wind turbine can be specified in terms of reliability (i.e., the probability that the WEC satisfactorily performs its intended function under given circumstances for a specified period of time). [38] In terms of energy loss, it is important that the turbine is reliable, particularly during periods of high wind, during which the WEC would generate high yield. The reliability issue is even more important offshore because rough weather conditions do not allow access to the WEC; therefore, the turbine remains unavailable until troubleshooting by a maintenance team is possible. [42] Finally, the energy loss due to unavailability reflects the performance of the service agent because he or she is responsible for keeping the WEC in good condition, organising spare parts and scheduling maintenance. Therefore, in a benchmarking analysis of service agents, both time-based availability and a metric that reflects the loss of energy during unavailability should be considered.

Figure 2-3 shows the selected parameters for the operating cost efficiency analysis. The only inputs are the specific operating costs (also referred to as the operating expenditures or OPEX), which comprise all expenditures that occur during operation, such as maintenance, insurance and administrative expenses. [13] In contrast to the capital costs, which are one-time investment costs, operating costs are usually assessed on an annual basis. Therefore, this operating cost efficiency analysis assesses the performance of different OWFs in different operational years. Installed capacity is again an output, which also appears to be a good measure in this case for the service agent's scale effort because it combines the number and size of WECs. In addition, the distance to shore has again been identified to be significant for these investigations. [43] Because there is usually only one port used as the base for the operational phase, which is not always the case for the construction phase, the distance to the operating port is used. Following the argument regarding a service agent's influence on the turbine's energy efficiency, a metric reflecting energy performance is needed. The optimal way to quantify energy performance might be to determine the energy lost during downtimes using the measured wind speed and the power curve of the wind turbine. [39,41] However, this calculation would require detailed operational data, which was not available for this study; therefore, the output energy performance was defined as follows:

$$\eta_p = \frac{AEP}{E_{kin\_wind} \cdot N} = \frac{AEP}{\frac{1}{2} \cdot A \cdot \rho \cdot v^3 \cdot t \cdot N} \tag{2}$$

where AEP designates the annual energy production of the OWF and N is the number of turbines. As shown in Figure 2-2, the kinetic energy of wind would be calculated precisely using the wind speed frequency distribution, which was also not available for this study. Thus, the annual average wind speed at hub height was used for v. In addition, ρ was assumed to be 1.225 kg/m^3, t was assumed to be 8760 h and for A, the rotor swept area of the respective plant's WEC was used. Therefore, the output energy performance reflects how efficiently the available kinetic energy content of the wind was converted into electrical energy during an operating year. At first glance, this approximation appears to be deficient because it incorporates all losses described before and not only the losses due to unavailability. However, because all other losses always account for nearly the same proportion of the energy yield and because DEA is a purely relative evaluation, this approximation appeared to be a valid approach. In addition, the time-based availability was also included as an output in the analysis.

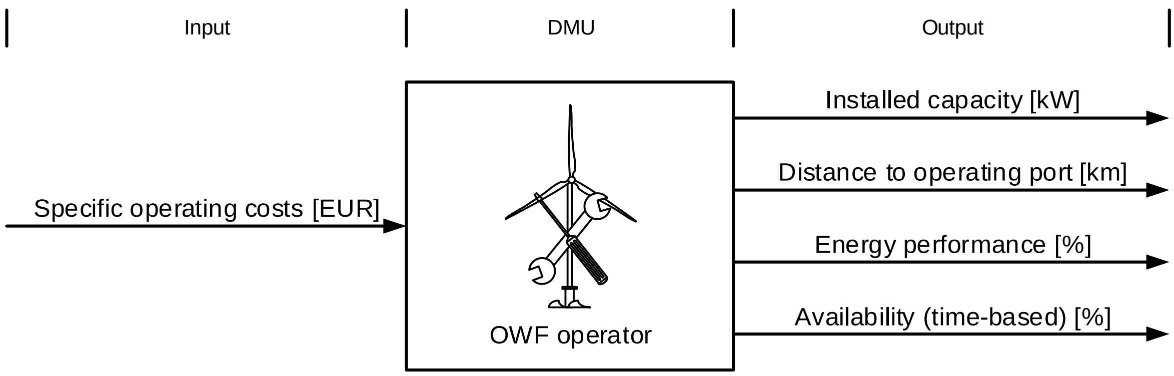

Figure 2-3: Model for operating cost efficiency.

Hence, the theoretical production function can be formulated in the following way: the higher the specific operating costs a service agent requires, the larger and the farther away from the operating port the OWF that is being maintained can be and the higher the energy performance and time-based availability will be.

2.2 Mathematical models

2.2.1 DEA application

DEA was developed with the aim of assessing the relative efficiencies of multi-input, multi-output production units. Therefore, DEA provides a methodology that allows for the identification of, within a set of comparable DMUs, those units exhibiting best practices and forming an efficient frontier. In addition, DEA allows for the measurement of the level of inefficiency of non-frontier units and identification of benchmarks against which they can be compared. [44] The main advantage of DEA is that prior assumptions regarding the underlying functional relationship between inputs and outputs are not required. [45] Because DEA is a well-established method for relative efficiency evaluation and extensively applied in the literature, only a brief description is provided in the following. The application presented in this article, and therefore the description provided, is mainly based on [44], which provides a focused overview, and [46], which is a comprehensive reference book for DEA.

The two basic DEA models are the CCR (Charnes-Cooper-Rhodes) model [47], which assumes constant returns to scale, and the BCC (Banker-Charnes-Cooper) model [48], which assumes variable returns to scale. Both models use a radial efficiency measure, which means that all inputs and outputs are adjusted proportionally. Depending on the selected orientation, either inputs are proportionally reduced while outputs remain fixed (input-oriented) or outputs are proportionally increased while inputs are held constant (output-oriented). These adjustments are made until the efficiency frontier, which is determined by the production possibility set (i.e., the set of feasible activities or, in other words, the combinations of inputs and outputs) is reached. Using the input-oriented model appeared to be appropriate for this application because it could ensure that the outputs would not be maximised to an implausible level. According to [44], the CCR model in the envelopment form can be formulated assuming a set of n DMUs, with each DMU j ($j = 1, \dots, n$) using m inputs x_{ij} ($i = 1, \dots, m$) and generating s outputs y_{rj} ($r = 1, \dots, s$), in the following manner:

$$
\begin{aligned}
\text{min} \quad & \theta_o - \varepsilon \cdot \left(\sum_{i=1}^{m} s_i^- + \sum_{r=1}^{s} s_r^+ \right) \\
\text{subject to} \quad & \sum_{j=1}^{n} x_{ij} \cdot \lambda_j + s_i^- = \theta_o \cdot x_{io}, \quad i \in 1, \dots, m \\
& \sum_{j=1}^{n} y_{rj} \cdot \lambda_j - s_r^+ = y_{ro}, \quad r \in 1, \dots, s \\
& \lambda_j, s_i^-, s_r^+ \geq 0, \quad \forall i, r, j \\
& \theta_o \text{ unrestricted}
\end{aligned}
\tag{3}
$$

For the BCC model, the following constraint must be added:

$$
\sum_{j=1}^{n} \lambda_j = 1 \tag{4}
$$

The result is an efficiency score θ_{CCR}^* (θ_{BCC}^*) between zero and unity for each DMU under consideration, which is a proportionality factor by which each input is reduced to reach the efficiency frontier. Thus, the radial projection to the frontier respective to the efficiency target for each input (output) can be calculated as follows:

$$
\begin{aligned}
\hat{x}_{io} &\leftarrow \theta^* \cdot x_{io} - s_i^{-*}, \quad i \in 1, \dots, m \\
\hat{y}_{ro} &\leftarrow y_{ro} + s_r^{+*}, \quad r \in 1, \dots, s
\end{aligned}
\tag{5}
$$

Additionally, it is also interesting to investigate the sources of inefficiency (i.e., whether the inefficiency is caused by the inefficient operation of the DMU itself or by the disadvantageous conditions under which the DMU is operating). Due to their characteristics (i.e., the radial expansion and reduction of all DMUs and their nonnegative combinations are possible resp. convex combinations of the DMUs, which form the production possibility set), the CCR (BCC) score is also called the global technical efficiency (local pure technical efficiency). A DMU is operating on the most productive scale size if both the CCR and BCC scores indicate full efficiency (100 %). Hence, a DMU that has full BCC efficiency but a low CCR score is operating efficiently only locally and not globally as a result of its scale size. Consequently, according to [46], scale efficiency is defined as follows:

$$\theta_{scale}^{*} = \frac{\theta_{CCR}^{*}}{\theta_{BCC}^{*}} \tag{6}$$

and because the CCR score is always lower than the BCC score, the value of θ_{scale}^{*} is also between zero and unity.

Finally, the definitions of the output availability and energy performance for the operating cost analysis imply that the measures can never exceed 100 %; this restriction had to be incorporated into the model by modifying the standard DEA models. According to the so-called bounded variable model described in [46], this limit can be considered by adding the following constraint:

$$\sum_{j=1}^{n} y_{bj}\lambda_j \leq l_u, \quad b \in 1, \dots, s \tag{7}$$

where l_u designates the upper bound for the bounded output y_b.

2.2.2 <u>Best-practice frontier</u>

The idea of calculating and providing the best-practice frontier arose from the policy of not publishing cost data for individual OWFs in this article. Otherwise, it would have been possible to simply provide the projection of the input for each OWF. However, to determine the best-practice frontier, a generic DMU was added. The first step was to choose a set of values for the generic DMU's outputs (e.g., 100 MW installed capacity, 10 m water depth, 10 km distance to shore) in the range between the minimum and maximum values of the respective output of the existing DMUs. The value for the generic DMU's input was chosen to equal the maximum value of the input of the existing DMUs. This ensured that the efficiency frontier was not altered. Calculating the projection of the generic DMU's input reveals the point on the efficiency frontier for the chosen set of output values. Thus, it was possible to vary the set of output values and trace the projection of the generic DMU's input to scan the best-practice frontier. Figure 2-4 shows a simplified visualisation of this procedure for the single-input, single-output case.

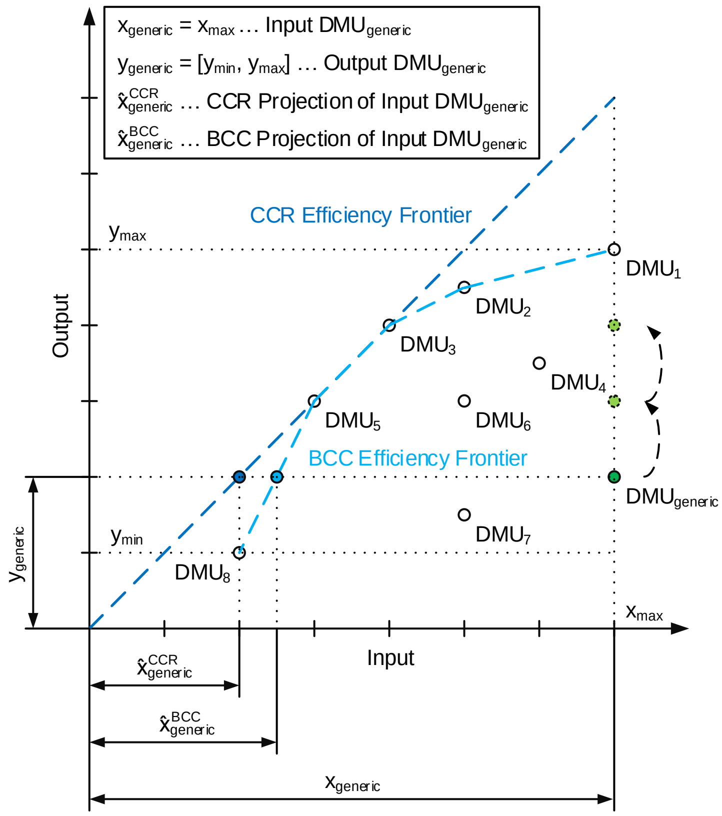

Figure 2-4: Determination of best-practice frontier.

2.2.3 Tobit regression and learning-by-doing

To investigate the relationship between certain factors—for example, the year of commissioning—and the efficiency scores obtained with DEA, the Tobit model proposed in [49] was applied. This model is a regression model that can address censored data and is needed because DEA efficiency scores are between zero and unity. Therefore, the Tobit model is a common second-stage analysis that has been frequently applied in the literature in conjunction with DEA. [50] Nevertheless, it is important to mention that this approach is not uncontroversial. For example, in [51], it is criticised that contextual variables used in Tobit models are probably correlated with the efficiency scores calculated previously, which leads to the inconsistency problem of estimators; therefore, the authors propose the use of bootstrapping. However, [52], [53] and [54] conclude after their investigations that the application of the Tobit model as a second-stage analysis is valid.

In contrast to similar applications in this field, every factor under investigation is analysed on its own instead of performing a multiple regression. In this manner, the relationship between the efficiency scores and every individual factor was determined. According to [50], the Tobit model applied in a DEA second-stage analysis can be described as follows:

$$\theta_j^* = \beta \cdot C_j + \varepsilon_j \text{ with } \varepsilon_j \sim N(0, \sigma^2)$$

$$\theta_j = \begin{cases} 0 & \text{if } \theta_j^* \leq 0 \\ \theta_j^* & \text{if } 0 < \theta_j^* < 1 \\ 1 & \text{if } \theta_j^* \geq 1 \end{cases} \tag{8}$$

where θ_j designates the CCR/BCC/scale efficiency score, β the set of parameters to be estimated, C_j the respective factor under investigation and ε_j the error term. Tobit regression was used to determine the relationship with respect to the factors YEAR (year of commissioning), CAP (installed capacity), CUMCAP (cumulative installed capacity), RATPOW (rated power of WECs) and NUMWEC (number of WECs). In addition, the factor OPYEAR (year of operation) was included for the operating cost analysis.

As described in the introduction, another objective of applying the Tobit regression model was to analyse cost development as a function of technological change, which is commonly described by learning curves. Therefore, the obtained relationship between cost efficiency and cumulative installed capacity was used to determine the so-called learning-by-doing rate. The concept of measuring learning through cumulative production or capacity was first introduced by [55] and describes the process of gaining productivity increases and cost reductions by the accumulation of experience. [56] A common approach is to investigate the learning-by-doing effect based on specific capital costs using the cumulative installed capacity as a proxy for the accumulation of experience. Following this approach, using the efficiency scores instead of specific capital costs and the equations provided by [57], the learning-by-doing effect can be calculated using the following equations:

$$\theta_t = \theta_{t_0} \cdot \left(\frac{CUMCAP_t}{CUMCAP_{t_0}}\right)^{\beta} \qquad (9)$$

$$LBD = 1 - 2^{\beta}$$

where θ_{t_0} / θ_t is the efficiency score at time zero / t, $CUMCAP_{t_0}$ / $CUMCAP_t$ is the cumulative installed capacity at time zero / t, β is the learning coefficient and LBD is the learning-by-doing rate. LBD is typically expected to be positive because a positive value indicates a reduction in unit cost. Because the cost efficiency should increase, it is important to note that for this application, LBD is negative in the case of a positive learning effect. Thus, a LBD of -10% indicates that a doubling of cumulative experience has led to an increase of 10% in cost efficiency.

3 Case study

Although the data collection was challenging, the DEA convention indicating that the minimum number of DMUs has to be greater than three times the number of inputs plus outputs [58] was adhered to. For the analysis of the capital cost efficiency, 22 ≥ 3 x (1 + 3) observations were included, and for the operating cost efficiency, 26 ≥ 3 x (1 + 4) observations were included.

3.1 Capital cost efficiency

For the capital cost efficiency analysis, the data for 3.6 GW of offshore wind capacity was used. The inclusion of plants in the analysis was based on the principles that they have a distance to shore greater than 3 km, an installed capacity greater than 30 MW and that the financial statements of the commissioning year be available. The data provided in Table 2-1 were selected very carefully, which means that only data from the owner’s official websites were used.

To ensure comparability, it was necessary to apply the same method for assessing the specific capital costs to every OWF. The method was applied using the highest value for tangible assets stated in the respective SPVs’ annual financial statements, which usually occurs during the year of commissioning because depreciation is applied afterwards. Tangible assets are all assets that have a physical form, such as property, plant and equipment. According to the international standard [86], the cost of a corresponding item is composed of the purchase price, any costs directly attributable to bringing the asset to the location, the conditions necessary for operation and the initial cost estimate for dismantling and removing the item and restoring the site on which it is located. Using this approach ensured a high quality of input data for the relative analysis and the generation of significant results. On average, the specific capital cost of these 22 OWFs was 2,992.90 EUR/kW (Median = 2,520.51 EUR/kW).

#	OWF	Ref.	Country	Commis-sioning	Number of turbines	Rated power kW	Installed capacity MW	Distance to shore km	Water depth m
1	alpha ventus	[59]	DEU	2010	12	5,000	60.0	60.0	30.0
2	Baltic 1	[60]	DEU	2011	21	2,300	48.3	16.0	17.5
3	Belwind Phase 1	[61]	BEL	2010	55	3,000	165.0	46.0	28.5
4	Barrow	[62,63]	GBR	2006	30	3,000	90.0	8.0	15.0
5	Burbo Bank	[64]	GBR	2008	25	3,600	90.0	7.0	5.0
6	Egmond aan Zee	[65]	NLD	2007	36	3,000	108.0	14.0	18.0
7	Greater Gabbard	[10]	GBR	2012	140	3,600	504.0	23.0	29.0
8	Gunfleet Sands 1 & 2	[66]	GBR	2010	48	3,600	172.8	7.0	7.5
9	Horns Rev 2	[67]	DNK	2010	91	2,300	209.3	30.0	13.0
10	Kentish Flats	[68–70]	GBR	2005	30	3,000	90.0	10.5	5.0
11	Lillgrund	[71]	SWE	2007	48	2,300	110.4	7.0	6.0
12	Lynn and Inner Dowsing	[72]	GBR	2009	54	3,600	194.4	7.0	9.5
13	Middelgrunden	[9]	DNK	2001	20	2,000	40.0	3.5	5.5
14	North Hoyle	[73–76]	GBR	2004	30	2,000	60.0	7.5	9.0
15	Ormonde	[77]	GBR	2012	30	5,000	150.0	10.0	23.5
16	Rhyl Flats	[78]	GBR	2009	25	3,600	90.0	8.0	9.5
17	Robin Rigg	[79]	GBR	2010	60	3,000	180.0	10.0	9.0
18	Rodsand 2	[79]	DNK	2010	90	2,300	207.0	4.0	10.0
19	Scroby Sands	[79–82]	GBR	2004	30	2,000	60.0	3.0	15.0
20	Sheringham Shoal	[83]	GBR	2012	88	3,600	316.8	20.0	20.0
21	Thanet	[84]	GBR	2010	100	3,000	300.0	12.0	22.5
22	Walney 1 & 2	[85]	GBR	2012	102	3,600	367.2	20.1	22.0
Minimum							40.0	3.0	5.0
Maximum							504.0	60.0	30.0
Average							170.1	15.3	15.2
Median							150.0	10.0	15.0

Table 2-1: Data for capital cost efficiency analysis.

3.2 Operating cost efficiency

Unfortunately, access to operational data of OWFs is very limited. Nevertheless, Table 2-2 provides an overview of the OWFs included in the analysis. One data source was the operational reports of the four UK round 1 OWFs—Scroby Sands [80–82], Kentish Flats [68–70], North Hoyle [73–75] and Barrow [62,63]—that were obliged to publish these data due to the UK Offshore Wind Capital Grants Scheme [87]. These reports contain data about wind speed, availability, annual energy production, operation and maintenance costs, etc. [88] provides a good summary and first analysis of these projects' data. The operation and maintenance costs mentioned in those reports were compared with the annual financial statements of the projects' SPVs, and the annual energy production was compared with data provided by [89] to ensure comparability. In addition, the offshore wind farms alpha ventus [59,90–92], Egmond aan Zee [93,94] and Middelgrunden [9,95,96] were included in the analysis. Operating costs for Middelgrunden were obtained from [95], whereas the data for alpha ventus and Egmond aan Zee required an assessment of the SPVs' annual reports.

For this case study, operating costs were defined to be all expenditures needed to keep the OWF operating over its lifetime. In other words, all costs stated in the profit and loss account of a SPV, such as administrative expenses, operation and maintenance costs for WECs and grid connection facilities, insurance costs, rent for port facilities, etc., were summed. Depreciations were not included, and governmental grant credits were subtracted. The specific operating costs of these OWFs account for 63.49 EUR/kW (Median = 46.88 EUR/kW) per year on average. Finally, the output energy performance was calculated using formula (2).

#	OWF	Ref.	Installed capacity MW	Distance to operating port km	Annual wind speed[a] m/s	Annual energy production[a] GWh	Energy performance[a]	Availability (time-based)[a]	Years of available data
1	alpha ventus	[59,90–92]	60.0	57.0	9.5	267.4	41.0%	95.8%	1
2	Barrow	[62,63]	90.0	17.0	9.1	231.8	29.6%	72.7%	2
3	Egmond aan Zee	[93,94]	108.0	20.5	8.7	337.8	42.5%	88.0%	6
4	Kentish Flats	[68–70]	90.0	11.8	8.0	230.1	44.2%	83.2%	3
5	Middelgrunden[b]	[9,95,96]	20.0	3.5	6.6	44.5	64.3%	95.0%	8
6	North Hoyle	[73–75]	60.0	16.2	8.4	183.9	39.5%	87.7%	3
7	Scroby Sands	[80–82]	60.0	8.5	8.0	142.3	35.6%	81.0%	3
Minimum			20.0	3.5			25.0%	67.3%	
Maximum			108.0	57.0			72.4%	98.9%	
Average			62.2	13.5			47.2%	87.9%	
Median			60.0	11.8			44.4%	88.6%	

[a]Average value over all operational years included in the analysis of the respective OWF.

[b]Only operational data of the 10 southern WECs owned by Middelgrunden Wind Turbine Cooperative were available and therefore considered in the analysis.

Table 2-2: Data for operating cost efficiency analysis.

3.3 Cost data preparation

For the relative cost analysis comparing OWFs that were commissioned (operated) in different years, it was particularly important to deflate costs well considered. Unfortunately, studies regarding costs of offshore wind often do not contain a description of how the costs were deflated, which seriously calls into question their quality, especially when OWFs that were commissioned more than 10 years ago are included. Moreover, it is very likely that the costs of offshore wind did not increase with normal inflation. For example, [8] showed that there is a relationship between capital costs and steel price, and [25] references the recent cost increase in offshore wind to a surge in prices of commodities, such as copper and steel. Considering the value breakdown of costs presented in [11], this is reasonable. According to [11], the CAPEX of a conventional OWF consists of 35 % labour, 34 % material and 31 % other costs, and the OPEX consists of 35 % labour, 14 % material and 52 % other costs. Labour costs are defined to include direct and indirect labour; material costs include all raw materials and components, consumables, equipment, plant and buildings, and other costs comprise services (e.g., vessels, cranes), insurances and other overheads. [97] also provides an illustrative breakdown of material in a 500 MW offshore wind farm with 100 turbines, which shows that a large proportion of the used material is indeed steel, copper, aluminium, etc., whose price increase was beyond the normal inflation rate. To incorporate this fact, all costs used in this analysis were deflated using a rate based on the cost split presented in [11] and using the deflator for labour costs, a commodity price index for the material costs and the GDP deflator for other costs provided by [98]. Therefore, all costs mentioned in this article refer to a price level in the European Union in 2012.

4 Results

4.1 Cost efficiency

Table 2-3 and Table 2-4 presents the results of the capital (operating) cost efficiency analysis in the form of efficiency scores. An efficiency score of 100 % indicates full cost efficiency, and values below indicate the level of cost inefficiency. When interpreting these results it should be kept in mind that DEA is a relative analysis method. Thus, one reason for the full capital and high operating cost efficiency of alpha ventus might be a lack of peers, i.e., OWFs that have specifics in the same range, which would ensure better comparability. Furthermore, the fact that the operating cost efficiency scores of each OWF are on fairly the same level—apart from a few outliers, which might be due to a year with good wind conditions or exceptional damage—indicate that the model generated reasonable results. Because the output installed capacity and distance to operating port do not change with operating year, this characteristic result is expected. Another part of the results would be the projections of all parameters (i.e., the target value assuming that the DMU operates efficiently). Because the provision of the projection would show the costs of individual OWFs instead, the best-practice frontiers are presented in the next section.

OWF	θ^*_{CCR}	θ^*_{BCC}	θ^*_{scale}
alpha ventus	100.00%	100.00%	100.00%
Baltic 1	54.97%	54.99%	99.95%
Belwind Phase 1	94.59%	96.43%	98.09%
Barrow	72.56%	81.85%	88.66%
Burbo Bank	31.82%	66.72%	47.69%
Egmond aan Zee	100.00%	100.00%	100.00%
Greater Gabbard	100.00%	100.00%	100.00%
Gunfleet Sands 1 & 2	55.08%	83.35%	66.09%
Horns Rev 2	100.00%	100.00%	100.00%
Kentish Flats	44.20%	85.29%	51.82%
Lillgrund	55.22%	100.00%	55.22%
Lynn and Inner Dowsing	59.35%	84.66%	70.11%
Middelgrunden	41.23%	100.00%	41.23%
North Hoyle	41.55%	66.88%	62.13%
Ormonde	73.21%	77.67%	94.26%
Rhyl Flats	50.10%	75.33%	66.50%
Robin Rigg	48.44%	68.77%	70.44%
Rodsand 2	68.69%	95.08%	72.25%
Scroby Sands	69.88%	78.82%	88.66%
Sheringham Shoal	53.54%	56.45%	94.85%
Thanet	72.19%	73.65%	98.02%
Walney 1 & 2	84.18%	88.39%	95.24%
Minimum	31.82%	54.99%	41.23%
Maximum	100.00%	100.00%	100.00%
Average	66.85%	83.38%	80.05%
Median	64.02%	84.00%	88.66%

Table 2-3: Results of capital cost efficiency analysis.

OWF	Operating year	θ^*_{CCR}	θ^*_{BCC}	θ^*_{scale}
alpha ventus	1.	98.73%	100.00%	98.73%
Barrow	1.	37.81%	37.81%	99.98%
	2.	40.97%	40.98%	99.98%
Egmond aan Zee	1.	68.70%	68.71%	99.99%
	2.	76.56%	76.57%	99.99%
	3.	86.30%	86.30%	100.00%
	4.	99.99%	100.00%	99.99%
	5.	97.32%	100.00%	97.32%
	6.	61.37%	100.00%	61.37%
Kentish Flats	1.	69.29%	69.29%	100.00%
	2.	69.30%	69.30%	100.00%
	3.	100.00%	100.00%	100.00%
Middelgrunden	1.	63.99%	69.64%	91.88%
	2.	100.00%	100.00%	100.00%
	3.	81.22%	100.00%	81.22%
	4.	62.94%	63.31%	99.41%
	9.	43.28%	79.72%	54.28%
	10.	50.44%	100.00%	50.44%
	11.	39.05%	39.31%	99.34%
	12.	42.74%	43.65%	97.91%
North Hoyle	1.	48.06%	48.07%	99.97%
	2.	58.71%	58.73%	99.97%
	3.	53.72%	53.74%	99.97%
Scroby Sands	1.	56.90%	59.41%	95.78%
	2.	50.86%	55.93%	90.94%
	3.	55.32%	57.87%	95.59%
Minimum		37.81%	37.81%	50.44%
Maximum		100.00%	100.00%	100.00%
Average		65.91%	72.24%	92.85%
Median		62.15%	69.30%	99.69%

Table 2-4: Results of operating cost efficiency analysis.

4.2 Best-practice frontier

In examinations of the best-practice frontier, it is important to keep in mind that DEA is a relative efficiency analysis method (i.e., the significance of the results strongly depends on the disposability of benchmarks for the DMU under investigation). DEA would, for example, also allow for the projection of the specific costs of OWFs that are farther offshore and at sites with greater water depths than those of the OWFs that were included in the analysis. However, the validity of such projections is questionable, and because the objective of this article was to provide reliable results, the best-practice frontier was calculated over a range where it was ensured that a sufficient number benchmarks were available. Therefore, the capital cost best-practice frontier shown in Figure 2-5 was assessed for installed capacities of 100, 200 and 300 MW, for distances to shore of up to 25 km and water depths of up to 25 m. Due to the limited database, the operating cost best-practice frontier was assessed for installed capacities of 60, 80 and 100 MW and distances to operating port between 5 and 20 km. The output energy performance was set to 45 %, and the time-based availability was set to 95 %. The results are shown in Figure 2-6.

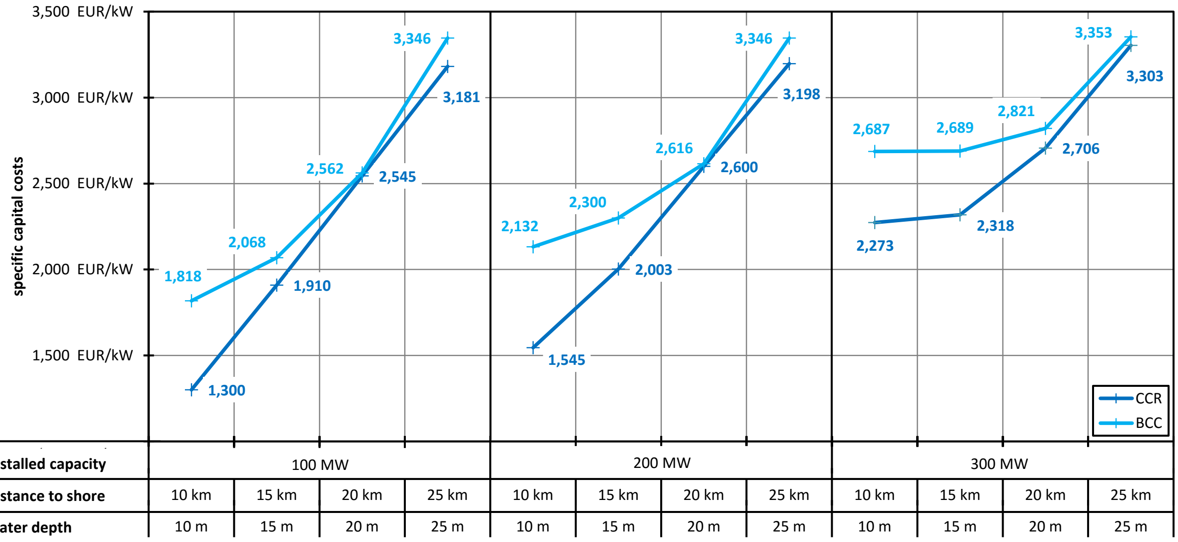

Figure 2-5: Capital cost efficiency frontier.

As described previously, the CCR score describes the global technical efficiency of a DMU, and the BCC score describes the local pure technical efficiency. Therefore, an OWF that achieves a level of costs lying on the BCC frontier is considered to be locally efficient but not globally efficient, which would require reaching the CCR frontier as well. The point (segment) where the two frontiers overlap is also interesting because it indicates the most productive scale size.

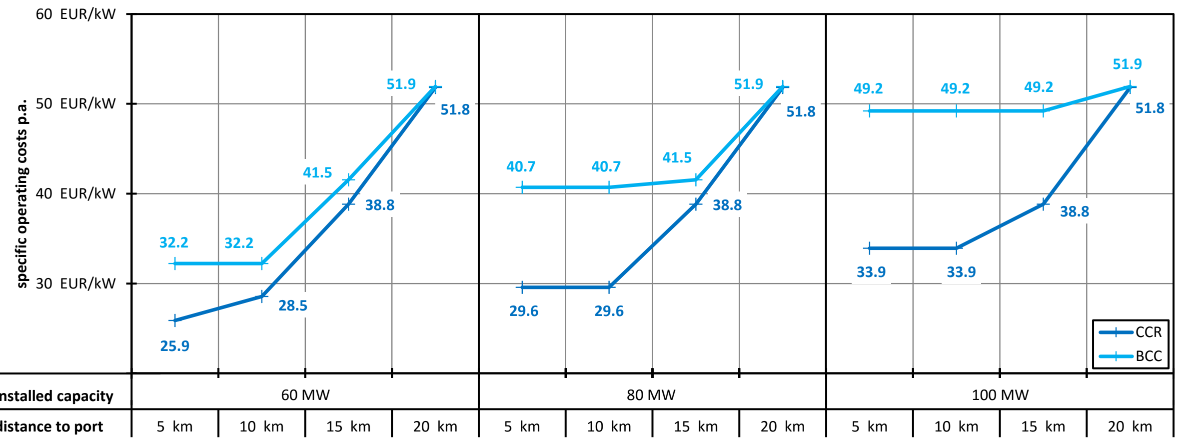

Figure 2-6: Operating cost efficiency frontier.

4.3 Tobit regression and learning-by-doing

Table 2-5 provides the results of the Tobit regression analysis performed during a second stage and the learning-by-doing rate for the different efficiency scores. For the factor CUMCAP, the cumulative installed offshore wind capacity in Europe provided in [1] was used.

	Capital cost efficiency			Operating cost efficiency		
	θ^*_{CCR}	θ^*_{BCC}	θ^*_{scale}	θ^*_{CCR}	θ^*_{BCC}	θ^*_{scale}
OPYEAR				-2.140×10^{-2}	3.796×10^{-3}	-2.573×10^{-2}
				(1.259×10^{-2}) .	(1.887×10^{-2})	(8.611×10^{-3}) **
YEAR	3.878×10^{-2}	-8.029×10^{-3}	4.821×10^{-2}	-2.478×10^{-3}	2.037×10^{-2}	-1.470×10^{-2}
	(1.715×10^{-2}) *	(1.498×10^{-2})	(1.352×10^{-2}) ***	(1.467×10^{-2})	(2.114×10^{-2})	(1.090×10^{-2})
CAP	9.178×10^{-4}	1.779×10^{-4}	9.410×10^{-4}	2.564×10^{-3}	1.999×10^{-3}	1.614×10^{-3}
[MW]	(4.629×10^{-4}) *	(3.694×10^{-4})	(4.301×10^{-4}) *	(1.162×10^{-3}) *	(1.797×10^{-3})	(9.528×10^{-4}) .
CUMCAP	7.533×10^{-5}	-9.586×10^{-6}	9.557×10^{-5}	1.958×10^{-6}	6.506×10^{-5}	-3.725×10^{-5}
[MW]	(3.398×10^{-5}) *	(2.862×10^{-5})	(2.705×10^{-5}) ***	(3.012×10^{-5})	(4.405×10^{-5})	(2.180×10^{-5}) .
RATPOW	8.060×10^{-2}	-5.485×10^{-3}	8.387×10^{-2}	1.456×10^{-1}	1.841×10^{-1}	5.737×10^{-2}
[MW]	(6.490×10^{-2})	(5.043×10^{-2})	(5.896×10^{-2})	(5.383×10^{-2}) **	(9.665×10^{-2}) .	(4.601×10^{-2})
NUMWEC	3.190×10^{-3}	1.023×10^{-3}	2.970×10^{-3}	$-1.535 \times 10^{+0}$	-2.046×10^{-3}	4.976×10^{-3}
	(1.569×10^{-3}) *	(1.261×10^{-3})	(1.465×10^{-3}) *	(1.477×10^{-1}) ***	(5.807×10^{-3})	(2.908×10^{-3}) .
LBD	-9.61%	0.93%	-10.28%	-0.25%	-6.89%	3.34%

***, **, *, . statistically significant at 0.1%, 1%, 5% and 10% level, respectively; standard errors are in parentheses

Table 2-5: Results of Tobit regression analysis and learning-by-doing effect.

5 Discussion

In general, the presented methodology based on the concept of DEA appears to provide a practicable approach for benchmarking OWFs. It enables stakeholders to evaluate the reasonableness of the capital and operating cost levels relative to those of other OWFs and to estimate the target costs that would be optimal corresponding to the specifics (operating parameters) of the OWF under investigation.

At first glance, the capital cost best-practice frontier indicates a strong dependence of the specific capital cost on distance to shore and water depth. This finding underlines the importance of quoting OWF specific capital costs as a function of the main specifics and the significance of this analysis. Furthermore, comparing the values with the scale factors provided by [15], the impact of these cost drivers appears to have been underestimated in the past. A closer look at the capital cost efficiency frontier reveals three implications. First, the most productive scale size suggested by the model (i.e., where the CCR and BCC frontiers touch) shows that smaller wind farms should be installed closer to shore and in shallower water. Second, at least for the range under investigation, it is possible to build a smaller OWF that is comparatively less expensive than a larger one at the same distance to shore and water depth. Third, the size of the OWF has a weaker impact on costs the farther away from shore and the deeper the water at the OWF site. These implications suggest that the best-practice OWFs have been developed and installed with negative economies of scale and that this effect levels off the farther offshore and the deeper the water at the OWF site.

Although the presence of negative economies of scale is also reported by other sources (e.g., [25]), it must be kept in mind that the presented frontiers reflect the best practices and not the overall trend. Furthermore, the evaluation of economies of scale in offshore wind should be well considered because installed capacity, which is commonly used to specify the scale of an OWF, does not refer to the number of produced and installed units (e.g., WECs, foundations). Thus, it is important to distinguish between dimension (installed capacity) and quantity (number of WECs). Considering the results of the Tobit regression analysis in this context reveals that for every 100 MW increase in OWF size, the CCR and scale efficiency improved by 9.2 % and 9.4 %, respectively, and by approximately 0.3 % per additional WEC. In conclusion, although the best-practice frontier reveals that it might be possible to develop and install a smaller OWF at a comparatively lower cost than a larger one, the overall trend shows that the larger the OWF is, the higher the capital cost efficiency will be. The best-practice frontier for the operating cost efficiency reveals similar implications, and the Tobit regression analysis also reveals the positive effect of installed capacity on cost efficiency. However, the database used for the operating cost efficiency analysis and the OWFs considered were rather small (the largest is Egmond aan Zee OWF, with an installed capacity of 108 MW). Therefore, it is questionable to what extent the results of the operating cost efficiency are applicable to large-scale projects that have recently become operational.

In general, the Tobit regression analysis generated the expected results. Nevertheless, it is remarkable that the expected relationships were verified partly even with high statistical significance. The results show that the global capital cost efficiency (CCR) improved by 3.9 % per year, and the scale efficiency improved by 4.8 % since the commissioning of the Middelgrunden OWF in 2001. Furthermore, the results reveal a negative relationship (-2.1 % p.a.) between the global operating cost efficiency (CCR) and the year of operation, which is reasonable because wear and tear induces increased maintenance effort and thus higher operating costs the older an OWF becomes. Finally, an interesting issue to explore may be the role of WEC size because all OWFs considered have been developed, installed and operated during a period of rapid increase in WEC size that is still on-going. Although it is not verified with high statistical significance, the results indicate the expected increase in capital and operating cost efficiency with increasing WEC size.

The learning-by-doing rate for capital cost efficiency shows that global technical and scale efficiency have increased significantly (-9.6 % and -10.3 %, respectively) with accumulated experience. These values contradict the low values of 3 % and 5 %, respectively, presented in [25] and thus demonstrate how important it is to incorporate the distance to shore and water depth in these investigations, which was also noted by the authors of [25]. However, it must be kept in mind that the concept of learning-by-doing usually relates specific costs to cumulative capacity, and the basis of this analysis were efficiency scores limited to 100 %.

Figure 2-7 shows a visualisation of specific CAPEX and OPEX estimations provided by key references in this field for the base year 2012 (partly adjusted). These estimations deviate significantly from each other and also from the figures processed and calculated in this analysis. Given that these reports are inter alia the basis of decision making on energy policy issues such as remuneration schemes and expansion targets again demonstrates the importance of reliable input data and the application of comprehensive and advanced cost analysis methods. However, the relative cost reduction targets presented in these publications appear to be realistic. The calculated learning-by-doing rate suggests that the benchmarks presented previously should be reached with an accumulated experience of approximately 12 GW, which corresponds to the year 2016 according to recent projections.

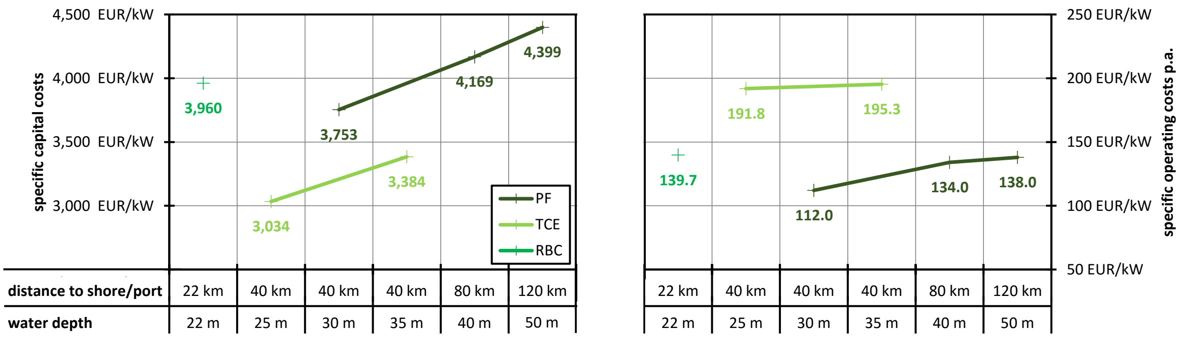

Figure 2-7: Specific CAPEX and OPEX estimations by PF [4]; TCE [5] (adjusted from 2011) and RBC [6] (adjusted from 2013).

Finally, it should be noted, which might also be the main point of criticism and uncertainty, that the results depend highly on the input data. It is clear that the more data included in the analysis, the more significant the results will be. Admittedly, the database for the operating cost efficiency was not excessively large, and the selection of input/output configurations was also influenced by the availability of data. In addition, there may also be other cost drivers that were not included in the model, such as the tightness in the market of wind turbine manufacturers and installation service providers. [25] However, the developed methodology generated plausible results, verifying the method's practicality for offshore wind cost analysis.

6 Conclusions

In this article, the functionality of the operations research tool DEA was exploited with the aim of providing a useful methodology that enables the evaluation of the relative capital and operating cost efficiency of OWFs based on their main specifics. Furthermore, best-practice frontiers were determined that overcome the difficulties regarding the appraisal of capital and operating costs by providing offshore wind stakeholders benchmark figures. The results revealed that more sophisticated cost assessments are needed and how meaningless the declaration of averaged specific cost figures for OWFs is. Finally, a Tobit regression analysis verified and quantified the expected relationships between the efficiency scores calculated by DEA and certain factors of interest, such as an increasing capital cost efficiency as a function of time, a decreasing operating cost efficiency as a function of the operating year and the presence of economies of scale and learning-by-doing. Gathering cost inputs mainly from annual reports ensured a particularly reliable database and high scientific quality, which stands out and will hopefully contribute to the development of an industry that is challenged to improve cost efficiency to gain competitiveness.

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PUBLICATION 3

The market value and impact of offshore wind on the electricity spot market: Evidence from Germany

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Abbreviations: German Renewable Energies Act (Erneuerbare-Energien-Gesetz (EEG)); transmission system operators (TSOs); average (AV); coefficient of variation (CV)

1 Introduction

Even prior to the disaster at the nuclear power plant in Fukushima, Germany's long-term energy strategy was dedicated to sustainable development of its energy supply and a reduction of its economic costs that also took into consideration long-term external effects and a conservation of fossil resources. [1] However, the energy turnaround ("Energiewende") that was enacted as a consequence, which designates a change of the energy mix towards a domination of renewable energy sources [2], and the nuclear phase-out in 2011 generated more emphasis and determination for this intention. [3] Wind energy is one of the key technologies that should ensure the success of the energy turnaround and is thus endowed with a benevolent subsidy scheme. Figure 3-1 shows the expansion of wind energy in Germany during the past several years and a medium-term prognosis until 2019. According to the current German Renewable Energies Act (Erneuerbare-Energien-Gesetz (EEG)) [7], the expansion target for onshore wind is defined to be a net (difference between addition and decommissioning) annual increase in installed capacity of 2.5 GW and a total offshore wind capacity of 6.5 GW in 2020 and 15 GW in 2030. This would lead to an electricity generation market share of at least 18% in 2020, which reflects the increasing importance of wind energy in the German electricity industry. [4]

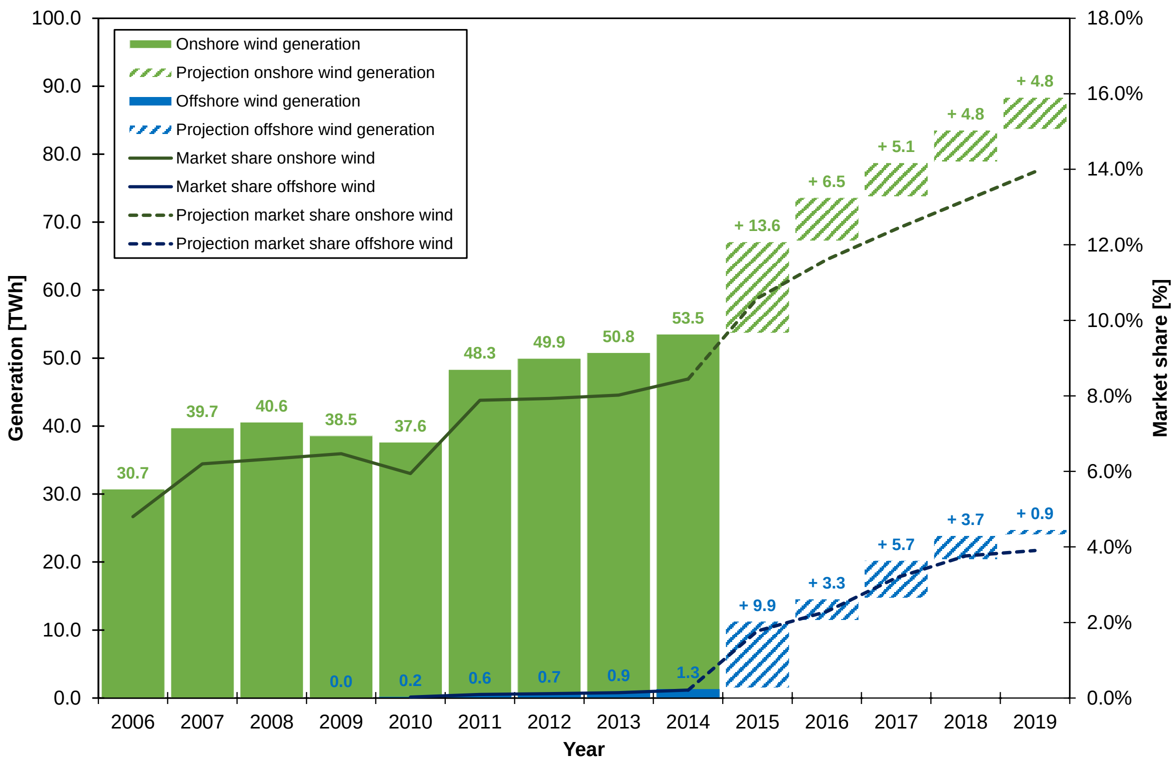

Figure 3-1: Increasing importance of wind energy in the German electricity market. [4–6]

Onshore wind in particular seems to have demonstrated that it is a key pillar of the German energy turnaround. By contrast, offshore wind is still in its nascent stage. There might be several reasons for this, such as the great distance to shore and water depth at the planning sites, which imply considerable effort. Another possible reason could be that the German state may have underestimated the burden that is coupled with the responsibility of ensuring grid connection for all wind farms far away from shore. These circumstances consistently promote discussion on the future role of offshore wind in the German energy turnaround, especially compared with its onshore counterpart in the battle for subsidies. The reviews [8] and [9] show that many pros and cons should be considered in this discussion. However, the economic effects occurring when onshore and offshore wind production is traded on the electricity spot market have not been part of these comparisons so far although they might be of significant importance in changing the energy mix. This article thus analyses the marketing of wind energy and its impact on the electricity spot market in detail with the objective of quantifying the difference between onshore and offshore wind and investigating whether offshore wind offers a benefit due to the steadier wind resource prevailing offshore.

The marketing and realised market value of wind energy is significantly affected by its property of being non-dispatchable because the operator is forced to feed-in and sell the electricity when there is wind, which is in contrast to dispatchable generators that can adjust their production in relation to the electricity market. This leads to a market value below the average market price because electricity is increasingly sold when the market price is rather low. This reduction in value is also referred to as profile costs and is the topic of several recent publications, of which [10] provides a comprehensive review. However, to the author’s knowledge, the market value has so far only been analysed for onshore wind. Thus, the first aim of this article is to assess the market value of offshore wind. As investigated in [11] for onshore wind in Germany, the spatial position has an effect on wind power revenues and therefore this assessment should show whether the argument of a higher and steadier wind resource prevailing offshore has a positive effect on the marketing of its electricity in addition to the increased energy yield. [12] The reason that this article might be the first analysis could be due to the lack of data availability, which was overcome by using weather data from measurement stations located in the German North and Baltic Sea in addition to feed-in data.

The variability of wind does not only have an impact on its own economics, however. In combination with the property of near zero marginal costs and supported by a benevolent subsidy scheme wind energy has a significant impact on the electricity spot market. The so-called merit order effect causes a price deterioration with increasing feed-in capacity. [13] A considerable amount of research has been performed on this topic, whereof [14] provides an comprehensive review until the year 2013 including the assessment region and period, reported price change and a short description of the used approach. Recent publications analysing the relationship between variable wind electricity generation and electricity price behaviour in Germany confirm the decreasing effect on the spot price. [14–18] In addition to that, [14] suggests that the impact of wind varies depending on the region and assessment method chosen, [16] reports that wind feed-in also increases spot price volatility and [17,18] indicate the load dependence of the merit order effect. Again, none of these analyses distinguishes between onshore and offshore wind. Thus, the second objective of this article is to investigate and quantify the impact of offshore wind energy on the electricity spot market compared with its onshore counterpart, which is a novelty in this field of research. The fact that its generation is less variable might be a reason for less deterioration and less variability in the spot market price, which would again be an argument in favour of offshore wind.

Modelling this impact is challenging, especially with the aim of generating reliable and significant results. In the literature this problem is generally solved by employing empirical analyses, simulation-based approaches or a combination of both. Most common when aiming for quantifying the merit order effect applying empirical analyses is the design of a regression model and applying it to historical data as, for example, done in [19] for the Spanish, in [20] for the Italian and in the before mentioned [14–17] for the German electricity market. Furthermore, [21] investigated the impact of weather conditions in the Netherlands and Germany on the Dutch electricity market and [22] the effect of wind feed-in on the level of spot prices and spot-price variance in Texas using also regression analysis. In contrast to that, simulation-based approaches require the design of an electricity market model that enables to simulate the impact of increasing variable generation on the market price. For example, the authors of [23] examined the price effect on the Iberian day-ahead market by applying a long-term system dynamics based model. In [24] a agent-based simulation platform enabled a detailed analysis of the price change caused by renewable energy in Germany and the authors of [25] developed a price demand dispatch model for the Australian National Electricity Market. Another interesting methodology is described in [26,27], where an artificial intelligence-based technique (M5P algorithm) was employed in order to quantify the merit order effect in Spain. Finally, a combination of simulation and empirical analyses was used for example in [18] for the German and in [28] for the Italian electricity market. However, it is remarkable that all these approaches require a considerable amount of market data and several assumptions and simplifications, which cause significant uncertainties, in order to gain a complete picture of the market at a specific moment or within a specific period that enables to correctly evaluate the impact of an additional amount of variable generation capacity. The difference between onshore and offshore might be rather small, which thus required a different approach.

The idea for the methodology presented in this article is derived from the intention to simulate exactly the cause of the price reduction, i.e., the merit order effect, and the understanding that the original ask and bid curve, which are the basis for price setting, reflect the required complete picture of the market at a specific moment. Thus, using the original ask curve, shifting the original bid curve dependent on the increasing wind feed-in and computing the market clearing again made it possible to simulate the impact of wind electricity exactly as it would be in reality. Although this approach seems to be quite obvious, it has, to the author’s knowledge, only been applied once in [29] for the Spanish electricity market. The reason might be that the design and implementation of an algorithm that reliably and precisely determines the market clearing for every hour of the years under consideration is quite sophisticated and computationally intensive. However, this seemed to be the best approach in order to generate significant results that enable factual conclusions to be derived and thus was used in this article to quantify the impact of onshore and offshore wind on the German day-ahead electricity market for the years 2006 – 2014. Furthermore, a differentiation was made between short-term and long-term effects because in the discussion of a decreasing market price caused by large amounts of variable renewable energy it is sometimes forgotten that the main objective of this expansion is to substitute carbon intensive energy resources and nuclear power plants. Thus, this article also investigates what happens in the long term when wind energy substitutes these base load power plants (see [30] for a complete discussion regarding short-term and long-term effects of renewable energies in electricity markets).

The next section begins with a description of the market environment for wind energy in Germany from an economic perspective, which should enable comprehension of the approach and the interpretation of the results. Section 3 provides the assessment results of the market value of offshore wind. Section 4 describes the methodology and implementation of the simulation, and Section 5 presents the results. Finally, these results are used to draw an overall conclusion in Section 6.

2 Market environment for wind energy in Germany

2.1 Remuneration scheme

In general, wind energy generation in Germany is financially supported either in form of a feed-in tariff or – in case of direct marketing – a market premium. [4] Until recently, wind farm operators were allowed to choose between the two remuneration options, but to constrain them to compete on the electricity market a revised EEG took effect in 08/2014, which allows a feed-in tariff only in exceptional cases (e.g., small power plants). Thus, now wind farm operators are obliged to trade their production themselves, and the feed-in tariff defined in the actual EEG represents a target value for the financial support. A wind energy producer in Germany therefore has two sources of revenue. On the one hand, the revenues obtained from trading electricity on the wholesale market, and on the other hand, the subsidy granted in the form of the market premium, which is defined to be

$$p_m = tv - mv \tag{1}$$

where tv is the target value and mv the market value. The latter is calculated as follows:

$$mv = \frac{\sum_{h=1}^{H} p_h^{mc} \cdot q_h}{\sum_{h=1}^{H} q_h} \tag{2}$$

where p_h^{mc} is the market clearing price at the EPEX Spot SE Day-Ahead Auction for the German/Austrian market area for an individual hour h, q_h the cumulative onshore and offshore wind feed-in capacity for this hour in Germany, respectively, and H the number of hours within the respective period. Table 3-1 provides the basic target values for the remuneration of wind energy before a degression is applied in subsequent years.

	onshore	offshore
period of entitlement	20 years	
base value	49.5 EUR/MWh	39 EUR/MWh
standard value	89 EUR/MWh for first 5 years	154 EUR/MWh for first 12 years
compression value		194 EUR/MWh for first 8 years
extension period with standard value	+ 1 month for every 0.36% the energy yield comes below 130% of the reference yield and 0.48% it comes below 100% of the reference yield	+ 0.5 months for every nautical mile beyond 12 nautical miles to shore + 1.7 months for every metre beyond 20 m water depth

Table 3-1: Target value for the remuneration of wind energy according to EEG.

2.2 Marketing

Information on how traders market wind energy on short-term electricity spot markets can be found in German energy laws [4,31,32], where it is stipulated that transmission system operators (TSOs) must ensure the optimal marketing of renewable energy remunerated in the form of a feed-in tariff with the diligence of a prudent electricity trader. It is also specified that the forecasted feed-in capacity of renewable energy for every hour of the next day must be offered price-independent at the day-ahead market. Furthermore, deviations between the forecasted feed-in capacity during the day and the amount of capacity already sold must be offered or purchased on the intraday market. Considering the fact that marginal costs for wind farm operators are almost zero, it is reasonable to assume that traders market wind electricity in a similar way because as long as the resulting subsidised remuneration per electricity unit sold is positive, the wind farm operators will continue trading the forecasted amount of electricity on the day-ahead market – even when the market price is negative – and adjust for production deviations on the intraday market. Hence, the main short-term trading floor for wind energy and thus the market under investigation in this article is the day-ahead market.

2.3 Day-ahead market

The so-called Day-Ahead Auction for the German/Austrian market area constitutes a market segment of the European Power Exchange EPEX Spot SE. Buy and sell orders submitted on this market, which are basically price/quantity combinations of exchange members seeking to make a transaction in a contract, are traded daily via auction trading either in the form of single-contract orders (one expiry) for one hour of the day or a pre-defined block orders (several expiries). Orders are accumulated but not executed in the order book until 12.00 pm the day before delivery. Afterwards an auction takes place, which aims to optimise the total welfare, i.e., the seller and buyer surplus. The first step is that all orders are added up to obtain an aggregated ask and bid curve. Assuming that the exchange member's interest is linear between two price/quantity combinations, the market clearing price p_{mc} and quantity q_{mc}, where the bid and ask curve intersect, are found. p_{mc} is the price at which all trades will be executed and the total welfare is maximal (see Figure 3-2). Negative prices were introduced at the German day-ahead market in 2008. [33–36]

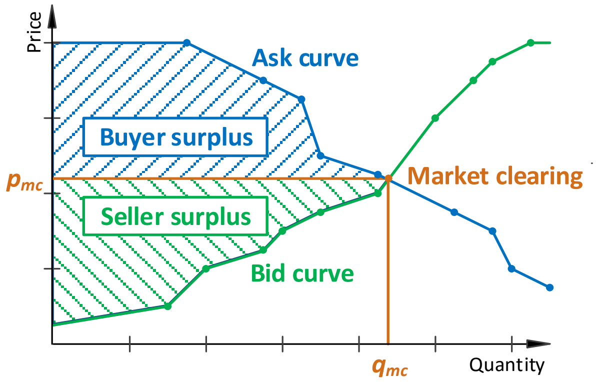

Figure 3-2: Market clearing at the day-ahead market.

3 Market value of offshore wind

The main challenge in assessing the market value of offshore wind was to ensure the availability of data because on the one hand data sources that provide hourly feed-in capacities often do not distinguish between onshore and offshore wind. On the other hand, because the deployment of large-scale offshore wind farms started only a few years ago, the period of data available is often rather short. That is also the case for Germany; the first offshore wind farm, alpha ventus, was commissioned at the end of 2009 and only since 2012 have the TSOs been obliged to provide offshore wind feed-in data separately. Thus, to obtain results for a significant period of time, wind data from measurement platforms in the German North and Baltic Sea [37] were also analysed. Another benefit of using these wind data in contrast to the feed-in data is that they do not contain the effect of continuously increasing capacity during the year. Figure 3-3 shows the position of the measurement platforms FINO 1 and FINO 3 in the North Sea, FINO 2 in the Baltic Sea as well as offshore wind project areas.

Wind data from these measurement masts provided by [39] at 90 m height were checked, cleaned up and used to calculate power generation for each hour based on a power curve from a generic 5 MW wind turbine with a 130 m rotor diameter. The effect of data gaps due to corrupt or missing wind data was neglected on the grounds that offshore wind turbines have availability in the same range and that the annual energy production for every year under consideration was also at a plausible level. Sources for actual onshore and offshore wind feed-in were provided by the TSOs [40–43] and a platform for market transparency [44]. Market clearing prices for the day-ahead market were provided by [45]. Only years with full data availability were considered and an hourly data resolution was chosen. This naturally required far more effort than a daily data resolution, but it ensured the highest possible quality of results. To have the ability to compare the market value of different energy technologies in different years it is common to use the market value factor, which is defined to be

$$f_{mv} = \frac{mv}{\overline{p_{mc}}} \tag{3}$$

where $\overline{p_{mc}}$ is the average market clearing price within the respective period. [10]

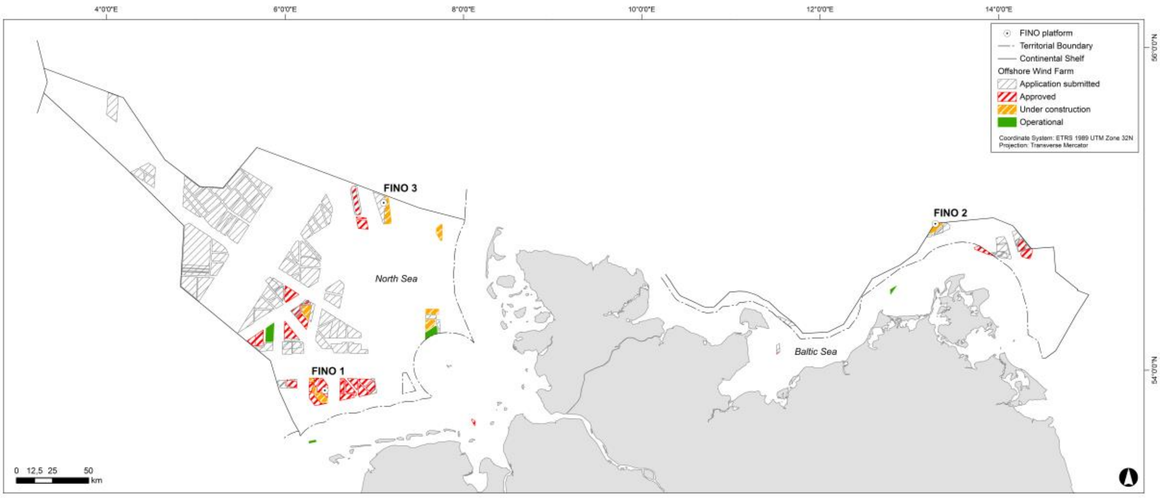

Figure 3-3: Offshore wind development areas and FINO platforms in German waters (based on data provided by [38]).

Figure 3-4 provides the assessment results for the years 2006 – 2014 and a projection until 2019 by [46]. Although the change in the market value factor of offshore wind and the measurement masts follows the same pattern as the market value factor of onshore wind, it is generally higher. This is indeed interesting and raises the question about the reason for this observation. The most obvious explanation for it might be that there are differences in the feed-in curves. Thus, Figure 3-5 shows the capacity factor curve for onshore, offshore and FINO1 as well as its characteristic parameters for the year 2013. The average and coefficient of variation (CV) reveal the expected property of offshore wind having a higher and steadier generation profile. If this characteristic causes a higher market value it might also be an indication for offshore wind having a less negative impact on the electricity market than its onshore counterpart. However, this can only be proven by a well-designed simulation that enables this difference to be worked out and includes the fact that there is already far more operational onshore wind capacity than offshore, which could be another explanation.

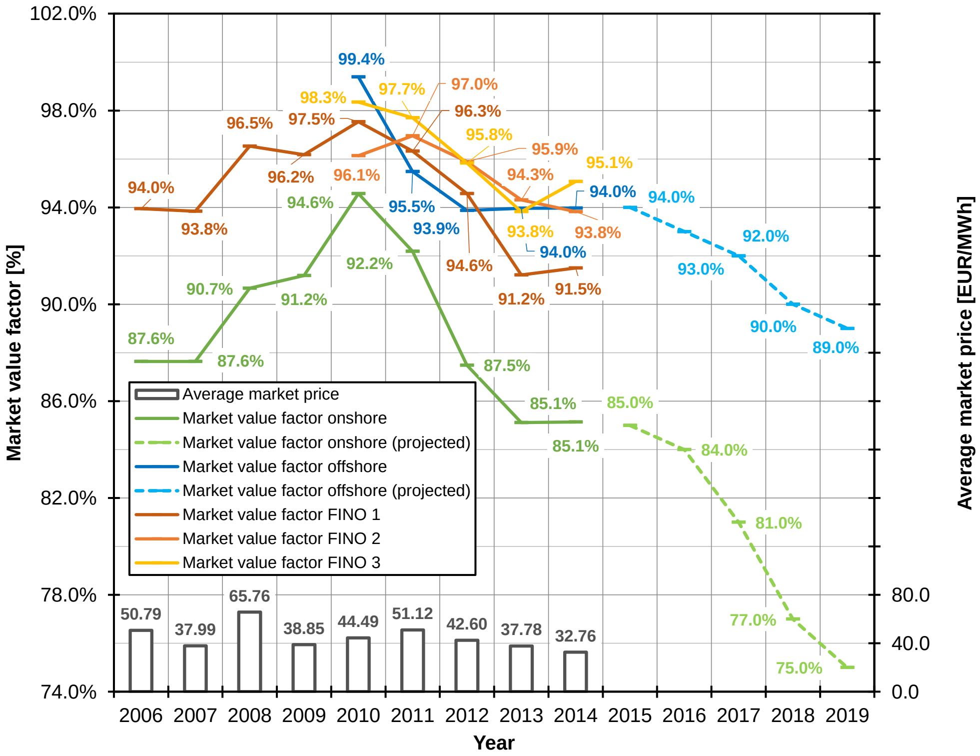

Figure 3-4: Market value of offshore wind in comparison with onshore wind in Germany.

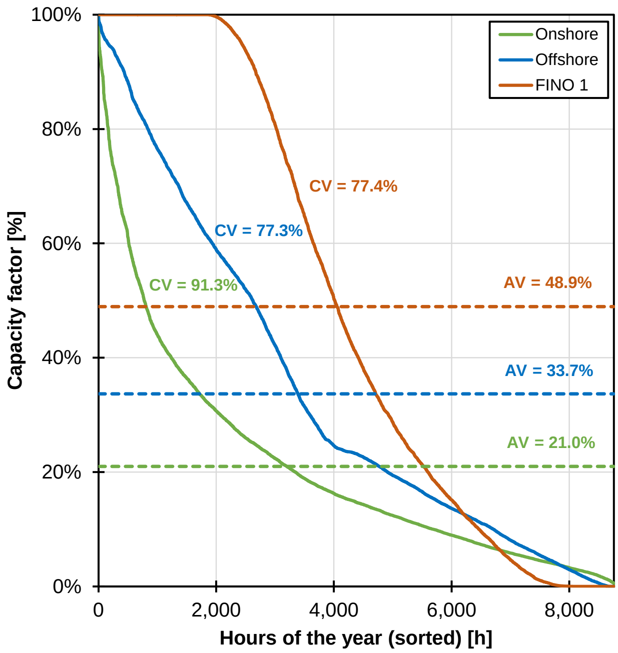

Figure 3-5: Capacity factor curve for onshore and offshore feed-in as well as an assumed 5 MW wind turbine at FINO 1 position incl. average (AV) and coefficient of variation (CV) in the year 2013.

4 Simulation

4.1 Methodology

The merit order effect (see Figure 3-6 (top)), which was simulated in the following, is based on the assumption that the demand curve is independent of the supply curve, which means that regardless of how much wind generation is traded on the day-ahead market the ask curve stays the same. This is in contrast to the bid curve. Due to the property of wind energy having near zero marginal costs and the support through subsidies, wind energy is offered at a low price. This results in a shift of the bid curve by the additional wind capacity q_{wind}, which in turn causes a shift of the market clearing and thus leads to a lower market clearing price p_{mc}^{wind}. The extent of this effect depends on the additional wind capacity and the shape and position of the bid and ask curve. Considering the fact that all of these influencing parameters vary for each hour of a year, it is obvious that the impact of wind feed-in cannot be assessed precisely by applying statistical methods to market clearing prices and quantities. It only enables a snapshot of past market conditions to be estimated, but an active projection of the impact should be interpreted with care. Hence, the results presented in the following were obtained by simulating this shift exactly using the original bid and ask curves from the day-ahead market provided by [47], feed-in curves for offshore and onshore wind and a calculated generation curve based on FINO 1 measurements for the years 2006 – 2014. The market impact was simulated for three levels of additional energy generation per year q_{add} – 5 TWh, 10 TWh and 15 TWh – from onshore and offshore wind, respectively. Applying the simulation to original data from the past ensured that the analysis is not falsified by a projection of input parameters. Thus the results reflect what would have happened if in the respective year a specific amount of onshore/offshore wind energy would have been added to the day-ahead market. The reason for using only FINO 1 data is that most offshore wind capacity will become operational in its region in the next years (see Figure 3-3) and the difference compared with FINO 2 and FINO 3 is rather small.

The first step was to determine the additional wind capacity for every hour of the year $q_{wind,h}$, which was obtained by calculating a multiplication factor α with which the wind feed-in of every hour of the year under consideration $q_{feed\_in,h}$ was multiplied aiming at an adjusted feed-in curve with a cumulative generation amount of the chosen level of additional energy per year:

$$\alpha = \frac{q_{add}}{\sum_{h=1}^{H} q_{feed\_in,h}} \tag{4}$$

$$q_{wind,h} = \alpha \cdot q_{feed\_in,h}, \qquad \forall h \tag{5}$$

Afterwards, the bid curve was simply shifted based on the additional wind capacity of the respective hour or, in other words, for every point on the aggregated bid curve the original price remained the same but the associated capacity was increased. Calculating the intersection with the original ask curve results in the simulated market clearing price p_{mc}^{wind}, which in turn enabled calculation of the market value. This methodology applied for every hour of the years under consideration ensured that the results represent an exact projection of reality without any simplification and generalisation. In contrast to the procedure for assessing the short-term impact described up to now, the long-term impact, i.e., wind replacing base load capacity (see Figure 3-6 (bottom)), was simulated by shifting the bid curve for a capacity $q_{\Delta,h}$, which is the difference between $q_{wind,h}$ and the base load generation capacity per hour q_{base_load} that is replaced:

$$q_{\Delta,h} = q_{wind,h} - q_{base\_load}, \qquad \forall h \tag{6}$$

The latter was calculated for each hour by simply dividing the level of additional energy generation per year by the number of hours of the year under consideration:

$$q_{base\_load} = \frac{q_{add}}{H} \tag{7}$$

Hence, in the long-term simulation the market clearing was shifted to higher (lower) capacities $q_{mc}^{\Delta,high\,wind}$ ($q_{mc}^{\Delta,low\,wind}$) in hours of high (low) wind generation $q_{\Delta,high\,wind}$ ($q_{\Delta,low\,wind}$) resulting in a lower (higher) market clearing price $p_{mc}^{\Delta,high\,wind}$ ($p_{mc}^{\Delta,low\,wind}$). This opens up another perspective of the issue of decreasing electricity market prices due to a rapid expansion of non-dispatchable renewable energy generation units because it enables to distinguish between the effect caused by the variable characteristic of the renewable energy source (long-term simulation) and, on the other hand, the effect of excess supply (difference between short-term and long-term simulation).

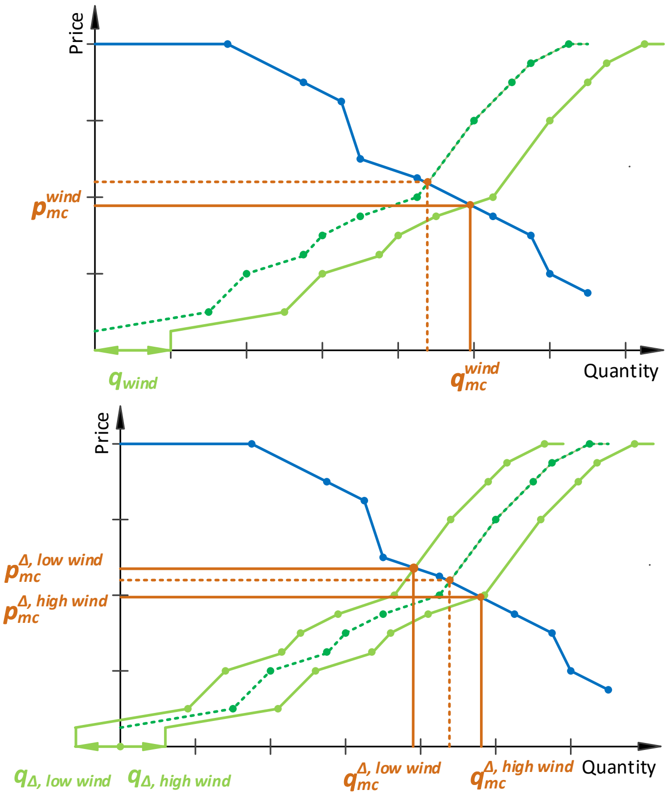

Figure 3-6: Simulating the merit order effect in the short term (top) and in the long term (bottom).

It is obvious that adding energy to this extent to the market will have a significant impact. Thus, to ensure the plausibility of the results a limit for negative prices was needed because the whole model is based on the assumption that wind power traders always bid the whole production price-independent or at a low price that does not influence the market clearing price. As discussed in section 2.1.2, this is plausible in general, but if the market clearing price decreases to a level where a profit would not remain even with subsidised remuneration, it is not reasonable that traders would continue to bid the whole production. Thus, it was assumed that wind generation is only put on the market up to a threshold of -76 EUR/MWh (onshore) and -157 EUR/MWh (offshore), which represents their levelised cost of electricity according to [48]. In the end, this constitutes the limit which should at least be covered by subsidies to ensure profitability. These figures might be a point of criticism, but it should be noted that the reasonable range of this trading threshold is rather small and a sensitivity analysis revealed that the impact on the results is negligible. Moreover, the results also cover an analysis of the number of hours with negative prices.

In the literature, whereof [49–52] provide an excellent overview, the bid and ask curves are often simplified using blocks, and the market clearing is determined using optimisation models. Unfortunately, these methods do not seem to apply to real market data, and the actual algorithm used to determine the market clearing at the EPEX Spot is unknown. Therefore, a custom algorithm was developed, which basically works in two steps and aims to determine the point of intersection between the aggregated bid and ask curve. Starting at a quantity of zero and continuously increasing it, the ask and bid price/quantity combination (p_a / q_a and p_b / q_b) where the bid price exceeds the ask price ($p_b \geq p_a$) is found (see Figure 3-7). Thereafter, the linear equation of a straight line passing through the price/quantity combination found and the one with less accumulated quantity (p_{a-1} / q_{a-1} and p_{b-1} / q_{b-1}) is calculated for both ask and bid. In case the intersection of these two lines (p_{mc} / q_{mc}) lies between the two price/quantity combinations used to determine their linear equation ($p_{a-1} \geq p_{mc} \geq p_a \wedge p_{b-1} \leq p_{mc} \leq p_b \wedge q_{a-1} \leq q_{mc} \leq q_a \wedge q_{b-1} \leq q_{mc} \leq q_b$), the market clearing point is found. Otherwise, the position of the intersection relative to the price/quantity combinations determined before reveal which adjustments are needed to find the correct market clearing price/quantity combination. This might not be the optimum approach to determine the market clearing and perhaps also not the fastest, but it turned out that it was the most stable and reliable in terms of computing absolute correct results. The algorithm was validated by simulating the actual market clearing, i.e., computing p_{mc} and q_{mc} assuming $q_{wind} = 0$ and comparing them with the real figures for every hour of every year under consideration.

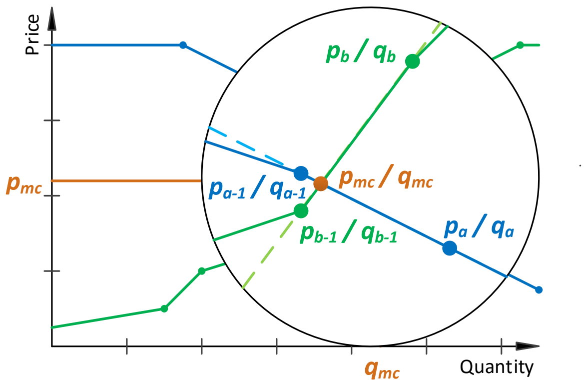

Figure 3-7: Visualisation of the algorithm for determining the market clearing.

5 Results

The three parameters of average market price factor, market value factor and number of extreme events were identified to give an indication of the impact on the electricity spot market and therefore were determined for the short term and long term. In general, the simulation that was developed generated reasonable and expected results, i.e., a decreasing market price and value as well as an increasing volatility subject to an increased wind energy feed-in. The applied approach of simulating the merit order effect for past years entirely based on real data (ask and bid curves, feed-in capacities and wind measurement data) ensured that as few assumptions as possible were required and thus neither errors (validation executed) nor significant uncertainties were imposed on the results. Nevertheless, it should be noted that the used feed-in capacities increased as a whole during a year due to a continuous expansion of wind power. This effect is not contained in the FINO measurement data; instead, it should be considered that the results based on these data reflect the production of a single wind turbine at one specific location and that there generally occurs a smoothing effect due to the spatial spread as more capacity is in operation. Lastly, secondary effects, such as a change in the generation mix, and strategic behaviour of market players are not included in the analysis. However, it is not expected that these effects have an impact on the overall conclusions drawn based on the results.

5.1 Market price

Figure 3-8 shows a visualisation of the resulting average market price factor, which is the simulated average market price related to the original average market price (= 100 %), in the case of adding 5/10/15 TWh in the short term and long term. The short-term results reveal the expected impact of a decreasing market price as more wind energy is added. In contrast, the long-term results of the simulation suggest that the substitution of base load by wind energy tends to increase the average market price. This is remarkable because this would mean that the sole reason for the actual price deterioration on the spot market is not the property of wind energy being non-dispatchable but rather the general excess supply. The reasons for the tendency to increase the market price might on the one hand be that there are more hours with less wind and on the other hand that there is a higher price sensitivity for a lower market clearing quantity. Similar to other publications in this field, Table 3-2 provides the average deviation of the market price (factor) per additional TWh of wind energy. The presented values and the graph show that a clear difference between the impact of onshore and offshore wind on the market price cannot be determined.

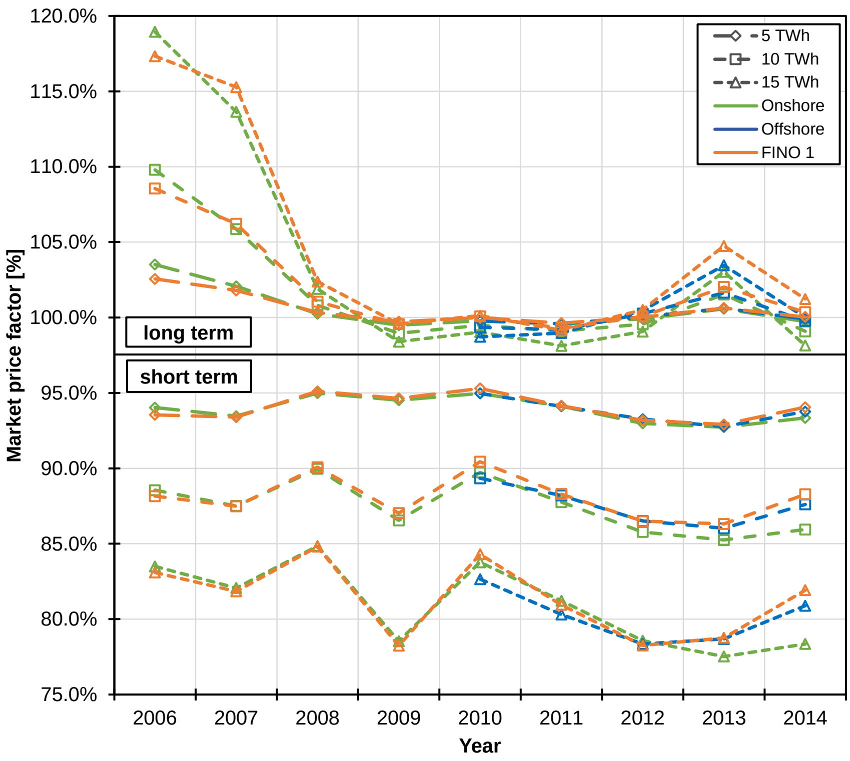

Figure 3-8: Market price factor in case of adding 5/10/15 TWh in the short term (bottom) and long term (top).

		short term	long term
market price (factor)	onshore	-0.56 (-1.27%)	0.11 (0.22%)
	offshore	-0.75 (-1.32%)	-0.19 (0.02%)
	FINO 1	-0.55 (-1.24%)	0.13 (0.30%)

Table 3-2: Average deviation of the market price (factor) per additional TWh wind energy in EUR/MWh (%).

5.2 Market value

As expected, the simulations reveal a decreasing market value caused by an increasing amount of additional wind energy. The results provided by Table 3-3 indicate a considerable difference between the short-term and long-term case. The values for the long term can be interpreted as the impact caused solely by the variability of the wind feed-in whereas the difference between the short-term and the long-term results represent the effect of general supply excess. However, the results again do not suggest lower impact of offshore wind compared with onshore wind.

		short term	long term
market value (factor)	onshore	-0.78 (-0.92%)	-0.33 (-0.92%)
	offshore	-0.81 (-1.08%)	-0.33 (-0.82%)
	FINO 1	-0.79 (-0.87%)	-0.28 (-0.84%)

Table 3-3: Average deviation of the market value (factor) per additional TWh wind energy in EUR/MWh (%).

5.3 Extreme events

Finally, the impact of variability that is induced by the feed-in of wind energy on the electricity spot market was determined. In general, a volatile market price implies aggravated predictability and thus increased risk in market operations for market participants (see [53] for further information regarding risk management in energy production and trading). More specifically, the excess of electricity supply generates negative price spikes, which can result in forced shutdowns and thus efficiency losses as well as financial losses with the consequence of an unprofitable operation in the long term. On the contrary, the occurrence of major electricity shortages generates positive price spikes and increases the necessity of reserve capacity to prevent blackouts. In this case, gas-fired power plants are placed in operation because they offer high operational flexibility and short ramp-up times (see [17] for a complete discussion on the role of different forms of energy within the electricity market). However, this in turn contradicts energy policy targets to decrease dependency on gas and the electricity supply by CO2 intensive power plants. All in all, increasing volatility imposes significant challenges on the electricity market environment.

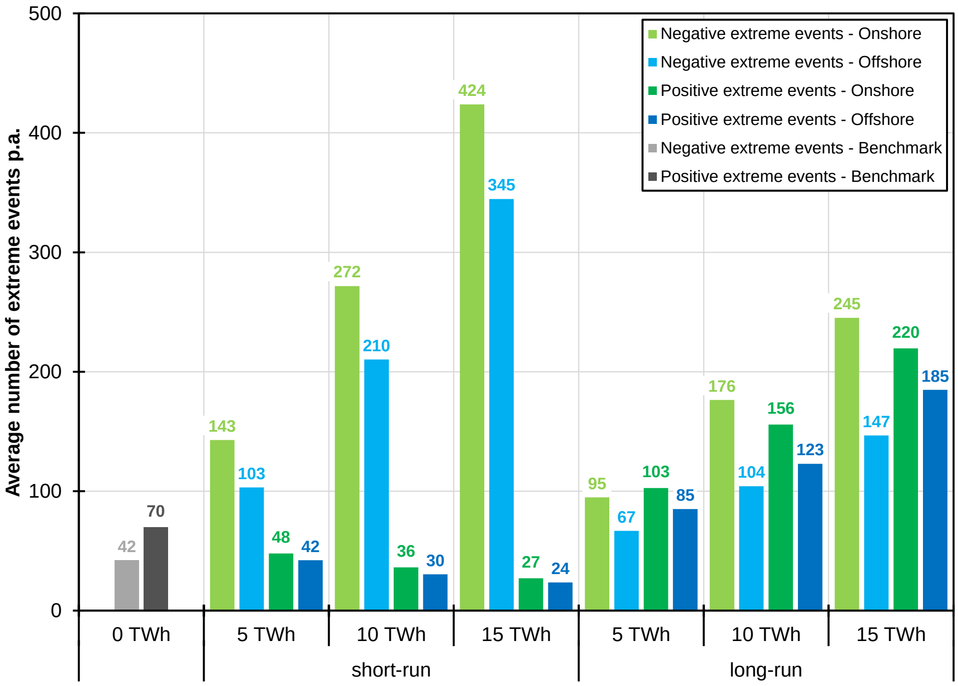

Figure 3-9: Average number of negative (market price < 0) and positive (market price > 2 x average market price) extreme events p.a. in the years 2010-2014.

The results shown in Figure 3-9 are provided using the average number of negative and positive extreme events per year as a measure of variability instead of other more common key figures for price volatility (e.g., annualised volatility [53]). These were considered to be the most suitable parameters for analysing results with this specific characteristic (inter alia negative prices) and deducing factual conclusions. Negative extreme events were defined to be hours where the market clearing price is negative and positive extreme events where it is higher than twice the annual average market price. FINO data were excluded, because the missing smoothing effect would falsify the variability analysis.

In general, the results of the short-term simulation show the expected shift to lower prices, i.e., the average number of negative (positive) price events increases (decreases) as the energy amount added increases (decreases). The long-term simulation reveals that the more wind energy is added the more negative and positive extreme events occur, which implies that it induces higher variability on the electricity spot market. Both the results of the short-term and long-term simulation suggest that these effects are stronger for onshore wind than for offshore wind, which is an indication of the positive impact of a steadier offshore wind resource.

6 Conclusion

Although a comprehensive assessment has revealed that the market value of offshore wind is in general higher compared with onshore wind, the results of the simulation suggest that the impact of additional energy amounts on the market value is rather the same. This allows to conclude that the only reason for the lower market value of onshore wind is the large amount of operational capacity already available, i.e., due to the limited spatial spread of the wind farms (most of them are located in northern Germany) the merit order effect is intensified during high wind periods. A similar conclusion can be drawn for the impact on the spot market price – there is an effect but it is very much the same for onshore and offshore wind. However, in addition to the results of the short-term analysis showing the expected decrease in the market price subject to an additional amount of energy, the simulation of the long-term impact revealed an interesting aspect beyond the evaluation of onshore versus offshore wind electricity. The results suggest that if the additional amount of wind energy replaces the same amount of energy provided by base load power plants, the market price would not change and thus the only reason for a decreasing market price is the excess of supply. This is remarkable because publications in this field tend to link the expansion of renewable energy with a decreasing market price. Although the reason might lie in how research questions are formulated, it casts a shadow on the German energy turnaround. The simulation demonstrated that the impact on the spot market price is not related to the property of renewable energy feed-in but to the consequence of a rapid expansion of renewable electricity supply without the envisaged concomitant phase-out of coal and nuclear power plants.

Nevertheless, a difference between onshore and offshore wind in terms of variability imposed on the electricity spot market was determined. The steadier wind resource prevailing offshore seems to result in less variability induced by the feed-in on the spot market price compared with its onshore counterpart. Because increasing volatility entails significant challenges for the electricity market environment – i.e., increased risks, negative market price and its consequences, support of unwanted peak-load power plants and the necessity of increased reserve capacity – this finding is indeed an argument in favour of offshore wind. To what extent lower variability may compensate for drawbacks such as the higher levelised cost of offshore wind electricity is a question for future research.

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PUBLICATION 4

The price of rapid offshore wind expansion in the UK: Implications of a profitability assessment

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Abbreviations: offshore wind farm (OWF); levelised cost of electricity (LCoE); Renewables Obligation Certificates (ROCs); Contract for Difference (CfD); capital expenses (CapEx); operating expenses (OpEx); Special Purpose Vehicle (SPV); Levy Exemption Certificates (LECs); Renewable Energy Guarantees of Origin (REGO); Internal Rate of Return (IRR)

1 Introduction

More than 10 years ago, the first offshore wind farm (OWF), North Hoyle, became operational in UK waters. This marked the start of a rapid expansion that led to the UK being the world leader in offshore wind since 2008. [1] In June 2015, 27 projects with a total installed capacity of 5.1 GW were operational, an additional 11.9 GW were either in construction or planning approval, and 5.2 GW were in the planning stage. [2] It seems that the target of up to 18 GW in offshore wind capacity by 2020 formulated in the UK Renewable Energy Roadmap [3] is achievable. However, part of this policy paper also describes the aim of reducing the levelised cost of electricity (LCoE) from offshore wind to 100 GBP/MWh by 2020. These two conflicting targets encapsulate the main challenge policymakers are faced with when designing support schemes for the efficient expansion of renewable energy. On the one hand, subsidies must offer enough incentive for entities in terms of remuneration and certainty to ensure the expansion. On the other hand, the profits of these entities should be kept at a minimum because they ultimately must be borne by the electricity consumers. Furthermore, the entities should be forced to develop, build and operate the renewable energy plants as efficiently as possible and to continuously improve the technology in order to reduce the LCoE. [4] The objective of this article is to assess the profitability of OWFs that became operational in the last few years and thus provide a review of the subsidy scheme for offshore wind in the UK that helped to facilitate this remarkable recent expansion.

Since 2002 the support mechanism for large-scale renewable electricity generation in the UK has been a green certificate system known as the Renewables Obligation. It requires electricity suppliers to source a specified proportion (known as the “obligation”) of the electricity they provide to customers from renewable sources. Suppliers demonstrate that they have met their obligation either by presenting Renewables Obligation Certificates (ROCs) or by paying a penalty (known as the “buy-out price”). ROCs are green certificates issued for the production of renewable electricity to operators of renewable generating stations. Hence, the operators sell their ROCs to suppliers (or traders), which allows them to receive a premium in addition to the wholesale electricity price. In this way, the certificates provide an incentive for the deployment of renewable generating stations. [5,6] However, this mechanism also implies risks for operators of renewable generating stations because they are exposed to volatile wholesale prices. The reduction of these risks and the resulting greater certainty and stability of revenues were the main motivation for implementing the Contract for Difference (CfD) scheme as a part of the Electricity Market Reform enacted in 2013. With the CfD, renewable electricity generators are paid the difference between the “strike price” – a price for electricity reflecting the cost of investing in a particular technology – and the “reference price” – a measure of the average market price for electricity. [7] In addition, the CfD equips the generator with clear contractual rights against a government-owned counterparty over a period of 15 years while securing the payments indexed to inflation, which further increases the level of certainty and works towards reducing financing costs. [8] The strike price for each OWF is determined in two ways: 1) using a competitive allocation process through an auction in case the assigned delivery year budget (known as the “pot”) is exceeded or 2) using a non-competitive process, which means that all applying OWFs receive the so-called administrative strike price (see [9] for a detailed description about its setting), i.e., the maximum accepted strike price for bids defined for the delivery year. [10,11] However, electricity generators under the RO scheme will continue to receive its full lifetime of support (20 years) until the scheme closes in 2037. [6]

LCoE, which original notion was to enable the comparison of the unit costs of different technologies over their economic lives, plays a key role in the debate over subsidy levels (e.g., it is one input for setting the administrative strike prices in the CfD scheme [12]) and was therefore also used in this analysis. Hence, it is worth to have a closer look at the definition of LCoE, which is provided and comprehensively discussed in [13]:

$$LCoE = \frac{\sum_{t=1}^{T} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{EP_t}{(1+r)^t}} \tag{1}$$

where EP is the energy production in year t, r the interest rate and C_t the (capital, operation and decommissioning) costs in year t. It is remarkable that many studies and reports focus on substantiating the inputs costs and energy production, whereas the interest rate is often assumed to be 5 or 10% and not justified in detail (e.g., [14]). A sensitivity graph provided in Figure 4-1 shows that the interest rate, which determines the financing cost, has a significant impact on the LCoE and therefore might lead to incorrect estimations when simplified (see [15] for a detailed discussion on its importance based on a LCoE study of solar PV systems). In general, the interest rate required by investors depends on the risk inherent to the project. In [13], it is stated that the assumed interest rates of 5 and 10% (referring to low and high risk scenarios) reflect the return on capital for an investor in the absence of specific market and technology risks. This simplification was made because it would be hard to produce comparable results for different technologies in different national markets otherwise. Thus it is essential when using the concept of LCoE for the evaluation of a specific technology in a specific market that assumptions about the interest rate are well considered.

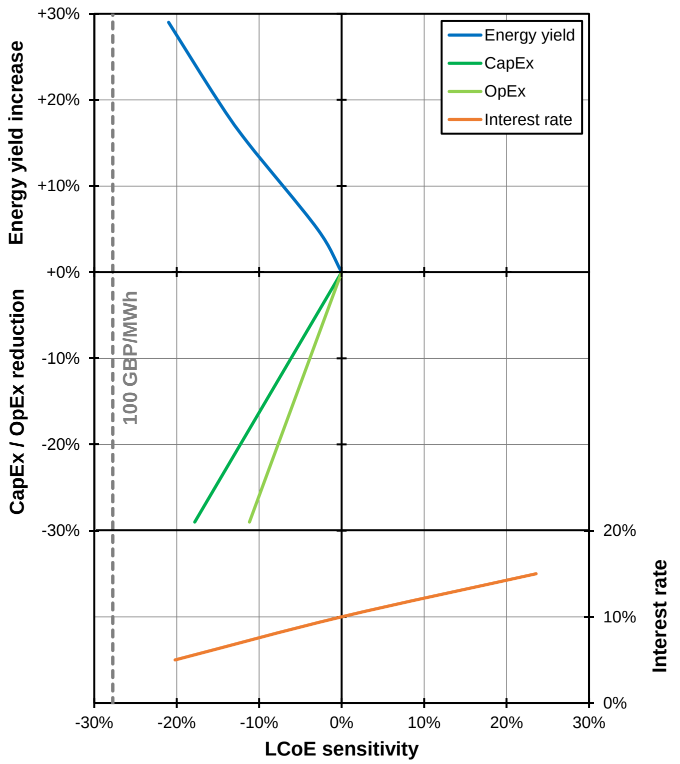

Figure 4-1: LCoE sensitivity subject to energy yield increase, capital expenditures (CapEx) / operating expenditures (OpEx) reduction and the interest rate (based on data provided by [12]).

In the recent report on electricity generation costs in the UK by the Department of Energy & Climate Change (DECC) [12], so-called technology-specific hurdle rates, i.e., the return on capital investors require to proceed with the project, are considered for the interest rate. The study also contains a comprehensive discussion on this topic based on several studies by consulting companies. Studies assessing hurdle rates apply two types of methodologies or a combination of them. The most common method is to employ the capital asset pricing model (CAPM), which determines the return on equity that an investor should expect on a financial asset by comparing its risk to other publicly traded assets. [16] This was, for example, done in [17] and in [18], where it was supplemented to account for asymmetric risk and real option values. Other studies rely on information provided in the available literature or gathered from interviews with industry participants, as in [19], [20] and [21]. Although these studies differ in regard to the year of publication, the assessment method and the underlying data, they report post-tax hurdle rates in the same range of 10 to 12% and predict a decreasing trend as the maturity of the technology increases. Interestingly, all of these studies have estimated current and expected future levels of hurdle rates with the aim to provide input for the design of future subsidy schemes, which is also the reason why they are referred to as cost of capital. However, no study has ever assessed on a large scale the actual ex post realised return on capital of OWFs that are already operational. This would enable the real LCoE to be calculated, including the real financing cost based on the remuneration rewarded to the entities. This article closes this gap and is motivated by reviewing the subsidy scheme and evaluating the degree of benevolence so that investment in offshore wind was ensured. An indication of potential over-subsidisation may be seen in the massive expansion of OWFs in the last several years. It could also be apparent in the outcome of the first CfD competitive allocation round [22], where the resulting strike prices of 114.39 and 119.89 GBP_{2012}/MWh (1.16 GW; delivery years 2017-2019) were significantly below the administrative strike price of 140 GBP_{2012}/MWh. [11] This also casts a shadow on the already non-competitive allocated 3.18 GW offshore wind capacity commissioning over the years 2017-2019 for administrative strike prices of 140 and 150 GBP_{2012}/MWh, respectively. [23]

However, the use of cost of capital instead of the realised return on capital is not the only vagueness that might result in incorrect estimations of the LCoE from offshore wind. Although several studies (e.g., [14,24–26]) have demonstrated that every OWF project is unique and that costs therefore vary significantly – especially in terms of such factors as distance to shore, water depth and project size – LCoE assessments are commonly based on case studies with averaged cost and energy yield figures. A different approach is thus needed, and the one applied in this article originated during research for a reliable database. It might be obvious that the most reliable sources for cost data are the annual financial statements of already operational OWF projects. Due to their designation as Special Purpose Vehicles (SPV), i.e., separate legal entities in which the owner is isolated from financial risks [21], the annual reports of every OWF project are officially deposited and accessible at the Companies House [27]. Hence, data from the financial statements of 14 operational OWF projects with a total installed capacity of 1.7 GW were fed into a developed standardised financial model that simulates all cash flows of an OWF over its lifetime applying basic accounting principles. Extrapolating revenue and cost streams for the remaining years of operation made it possible to simulate the profitability of the OWFs. This modelling approach stands out because other publications in this field, such as [25], comparing the financial attractiveness of potential OWFs in European countries, [28], assessing the profitability of two early-stage OWFs in the UK, and [29], analysing the profitability of existing wind farms in Portugal employ rather simple discounted cash flow models that do not consider financing, taxation and accounting. Considering the facts that the purpose of a discounted cash flow model is to take into account the time value of money and that the financing structure, taxation and accounting significantly influence the timing of payments, it is obvious that this simplification might be sufficient for an estimation, but it does not reproduce the reality (see [30] for a detailed discussion on accounting and taxation issues in financial modelling). Hence, modelling every OWF project individually considering accounting and taxation and based on its original cost data and financing structure, which is a novelty, ensures the lowest possible falsification of the results. Finally, the use of input data of the highest possible quality and the large scope of this analysis ensures that it is of significant value for offshore wind stakeholders. However, it should be noted that the intention of this publication is to provide reliable scientific analysis and not to compromise anybody on any account. Thus, the cost data and calculated profitability of individual OWFs' SPVs are intentionally not quoted.

In the next section, the approach is described in detail. It comprises a description of the financial model (2.1), the extrapolation procedure (2.2), the calculation of the result figures return on capital and LCoE (2.3) and, finally, the data used (2.4). Section 3 provides the results, including a sensitivity analysis, that are subsequently discussed in section 4. Finally, in section 5, an overall conclusion is drawn.

2 Approach

2.1 Financial model

The standardised financial model for an OWF project was developed based on International Financial Reporting Standards (IFRS), which are publicly available at [31]. All cash flows are modelled in the three core financial statements: the statement of comprehensive income, the statement of financial position and the statement of cash flows (see Figure 4-2). The necessary information for reconstructing these financial statements is provided in the annual reports of the OWF projects' SPVs. The simulation starts with the year of commissioning, i.e., the year with the highest value for property, plant and equipment, as depreciation is applied afterwards. Subsequently original financial data of the first years, as they were available, were incorporated into the model and the remaining years of the OWF's lifetime were simulated. Although OWFs are now built for an operation of 25 years, almost all OWFs under consideration stated in their annual reports that a lifetime of 20 years is envisaged; thus, all OWFs were simulated for 20 years of operation. Based on the necessary assumption that unforeseen expenses and earnings do not occur during the remaining years, the simulation was rather straightforward. In principle, it was necessary to extrapolate only the revenue (revenue and other income) and cost streams (cost of sales and administrative expenses), which is described in detail in the next section. All other parameters could then be derived by applying accounting principles.

Statement of Comprehensive Income

+	Revenue
+	Other income
-	Cost of sales
-	Administrative expenses
-	Finance costs
=	**Profit before tax**
-	Income tax expense
=	**Profit for the year**

Statement of Financial Position

	Non-current assets
+	Property, plant and equipment
+	Intangible assets
	Current Assets
+	Cash and cash equivalents
+	Other current assets
=	**Total assets**
	Liabilities
+	Shareholder loan
+	Bank loan
+	Deferred income (Governmental grants)
+	Provisions
+	Other liabilities
	Equity
+	Share capital
+	Retained earnings
=	**Total equity and liabilities**

Statement of Cash Flows

	Cash flows from operating activities
+	Profit for the year
+	Depreciation of property, plant and equipment
+	Amortisation of intangible assets
+/-	Change in other current assets
+/-	Change in deferred income (governmental grants)
+/-	Change in provisions
+/-	Change in other liabilities
=	**Net cash flow from operating activities**
	Cash flows from investing activities
-	Acquisition of property, plant and equipment
+	Sale of property, plant and equipment
=	**Net cash flow from investing activities**
	Cash flows from financing activities
-	Repayment of loans and borrowings
-	Dividends paid
=	**Net cash flow from financing activities**
=	**Net changes in cash and cash equivalents**

Figure 4-2: Structure of financial statements.

It is worth commenting on the derivation of following accounts in detail:

- In the year of commissioning property, plant and equipment comprises the original purchase price of the OWF's components, such as wind energy converters, foundations and electrical infrastructure; the costs attributable to bringing them to working condition for their intended use; and the financing costs that are capitalised during development and construction. Hence, it reflects the so-called capital expenses (CapEx), which are commonly used in cost assessments for representation of the initial investment. From the start of operation, depreciation commences in order to write off the value, less any estimated residual value, over the expected life time in a linear manner.
- The decommissioning provision was the only provision that was maintained over the lifetime of the OWF. Its amount stated in the annual reports reflects the net present value of the estimated cost of decommissioning at the end of the OWF's useful life based on expected price levels and the technology on the balance sheet date. Thus, the declared amount was kept as a provision and cleared with a cash reserve in the last year of operation.
- Some of the OWFs under consideration received government grants [26], which are included as deferred income in the statement of financial position and amortised over the useful economic life of the OWF through the statement of comprehensive income.
- Current assets were dissolved, as far as possible, in the first year of simulation because it was not possible to anticipate how they will evolve during the remaining years. This was also the reason why cash flows from investing activities were not considered further in the simulation.
- The profit of the year in the statement of comprehensive income was calculated after applying the future standard UK corporation tax rate of 20% [32]. Hence, the resulting return on capital is considered to be post-tax. [33]
- Almost all OWFs under consideration were funded entirely by their shareholders, i.e., the entities developing, constructing and operating the OWF – in most cases this was

an energy utility – that granted a loan to the SPV that covers all initial expenses. This loan is repaid including interest with future profits during the OWF operation. The interest rate of this liability, so-called amounts owed to group undertakings, is defined in the annual reports and often tied to the LIBOR (London Interbank Offered Rate). Therefore, the applicable interest on these loans (LIBOR was assumed to be its average of the last 20 years) was considered in the statement of comprehensive income.

- In general, the disbursement mechanism defines that debt capital, such as bank loans, is given priority. However, for all OWFs under consideration, the debt capital, where applicable, was already repaid when the simulation started; therefore, it did not have to be considered. Thus, the loan provided by shareholders was first disbursed, and afterwards, profits were distributed as dividends.

2.2 Extrapolation

2.2.1 Revenue

In general, all OWFs under consideration may have generated revenue from trading electricity on the wholesale market, Renewable Obligation Certificates (ROCs) and Levy Exemption Certificates (LECs). Figure 4-3 (left) shows the price trend of these revenue sources since 2004. As a rough benchmark for the earnings from electricity sales the average market price at the UK Day-Ahead spot market [34] is provided. However, due to the variable feed-in, the realised market value of offshore wind is likely to be lower than the average spot market price (see [35] for a complete discussion). The number of ROCs awarded for each MWh generated differentiates among the OWFs dependent on the year of commissioning and operation between 1, 1.5 and 2 ROCs. These certificates are tradeable commodities with no fixed price (see [6,36] for a detailed description concerning price formation). The price trend of the ROCs provided is based on data from [37], which is a trading platform that enables renewable electricity generating stations to sell certificates through an auction. Finally, LECs provide suppliers with some of the evidence required to demonstrate to HM Revenue and Customs (HMRC) that electricity supplied to UK business customers is exempt from the Climate Change Levy (CCL), which is a tax with a rate defined in [38] on UK energy business energy use. [39]

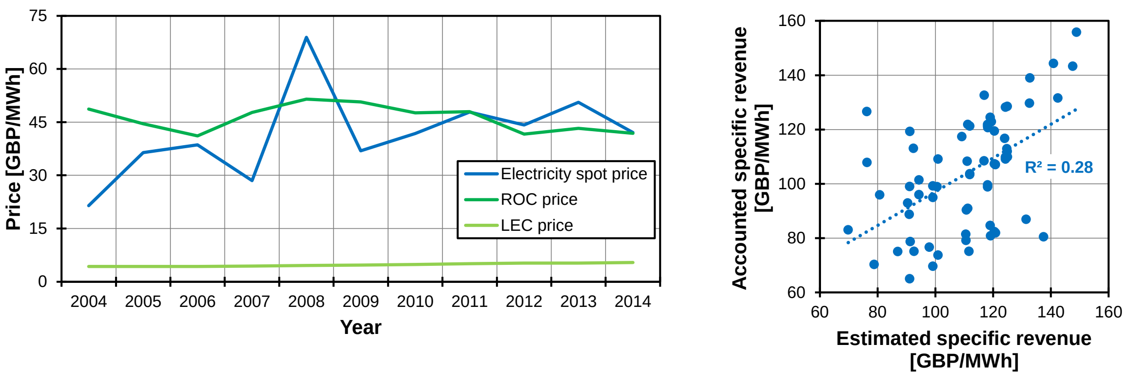

Figure 4-3: Price trends of revenue sources (left) and a comparison between estimated and accounted specific revenue (right). [34,37,38,40]

Based on the price trends of the three revenue sources, it is possible to compare the accounted specific revenue in the OWFs' SPVs with an estimate, as shown in Figure 4-3 (right). The amount of generated electricity and redeemed certificates per OWF and year was calculated based on data published in [40]. This database provides the number of ROCs and Renewable Energy Guarantees of Origin (REGO) awarded for each generating station. The latter is used to certify that the electricity was produced from eligible renewable energy sources and has no cash value. [41] But as it is granted for each MWh (each kWh prior to 5 December 2010) of produced electricity, it also reflects the energy yield and number of LECs issued for the generating station. However, the graph shows that there is not a perfect correlation between the accounted and estimated specific revenues, though it is reasonable to use it as an estimation. There might be several reasons for these deviations; for example, the earnings from sale of certificates may not necessarily be realised in the year of production. Thus, the revenues were extrapolated using the average energy yield of the OWF under consideration and multiplying it with a projection of the total remuneration comprising all three sources of revenue. It was assumed that all OWFs receive the same number of ROCs (1/1.5/2) as they did in the last year of available data until the end of their operating life. Thus, a start value for the total remuneration in the first year of simulation for each level of ROCs (1/1.5/2) was defined using linear regression. In subsequent years, an annual rate of increase of 2.2% was applied for the base case, which equals the average inflation in the UK over the last 20 years [42]. Furthermore, a varying annual rate of increase was additionally applied within the scope of a sensitivity analysis.

2.2.2 Cost

Apart from revenues, the costs accruing during operation, which are also referred to as operating expenses (OpEx), had to be extrapolated. These costs are accounted as the cost of sales and administrative expenses and were adjusted by the depreciation. An assessment revealed that specific OpEx levels vary significantly between each OWF and operating year, but on the whole, they increase with operating life (see Figure 4-4). This might have, on the one hand, the economic reason that inflation leads to higher labour and material costs and, on the other hand, the technical reason that wear and tear increases maintenance efforts. The latter effect was estimated to occur at an annual rate of increase of 6.5% after deflating the OpEx gathered for this analysis. This is remarkable and shows that neglecting or underestimating this effect may have a significant impact on the results.

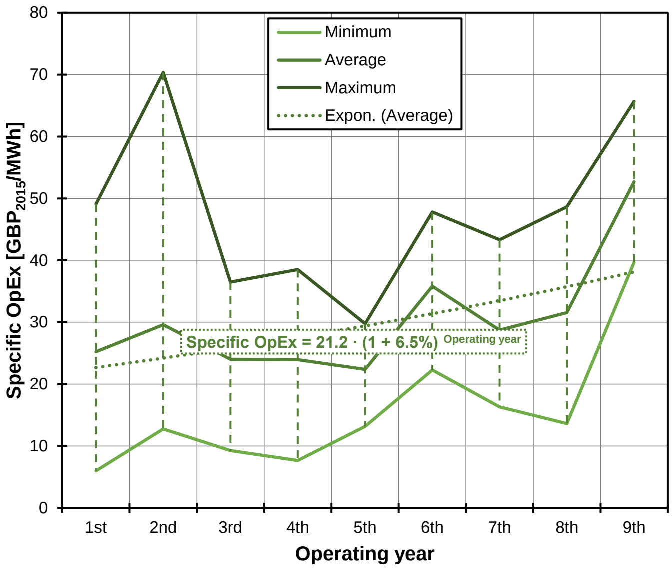

Figure 4-4: Development of specific OpEx levels subject to operating year.

It is reasonable to assume that the reason for the variation in specific OpEx levels between the OWFs are their different properties, such as distance to shore or number of turbines, which leads to varying maintenance efforts. This is why, similar to the case of revenue extrapolation, an individual start value using linear regression for the first year of simulation was calculated and in subsequent years the specific OpEx values were extrapolated by applying an annual rate of increase of 2.2% reflecting the inflation for the base case and a varying rate within the scope of a sensitivity analysis.

2.3 Return on capital and LCoE calculation

2.3.1 Return on capital

In contrast to the cost of capital, which is commonly employed in LCoE assessments and which designates the expected cost in order to obtain financing for a project, the return on capital designates the expected or realised profit on the capital invested in a project and thus is used in the following for evaluating the profitability of OWFs. It is important to note that this metric reflects the return on the entire capital employed, i.e., equity and debt capital. This is similar to the weighted average cost of capital (WACC), which is often used for LCoE calculations and weights the cost of equity and debt according to the capital structure. The most commonly used indicator for measuring the return on capital of a project is the Internal Rate of Return (IRR), which is the interest rate that equates the net present value of a project's positive and negative cash flows (PCF_t and NCF_t). Using the basic equation for the project IRR according to [43], the return on capital RoC was calculated by solving the following equation:

$$\sum_{t=0}^{T} \frac{NCF_t}{(1+RoC)^t} = \sum_{t=0}^{T} \frac{PCF_t}{(1+RoC)^t} \tag{2}$$

NCF_t comprises the contribution of equity (share capital and shareholder loans) and debt capital (bank loans), while positive capital cash flows include the payment of interest and dividends, repayment of debt capital, equity capital and shareholder loans. The timing t of these payments resulted from the financial model described above.

2.3.2 LCoE

Based on the return on capital calculated for each scenario, the impact on the LCoE was assessed. Thus, in equation (1), the interest rate r was replaced by return on capital. In general, for all other parameters, the same values used for the simulation were assumed. Hence, the lifetime T of all OWFs was assumed to be 20 years; the annual energy production EP_t, derived from the number of REGOs was used for the years in which data were available, and an average value was used for subsequent years. Costs were distinguished between $CapEx$, $OpEx$ and decommissioning expenses ($DecEx$), which arise at the end of the lifetime ($t = 20 = T$). As described, $CapEx$ reflects the initial investment and can be assumed with the amount accounted for in property, plant and equipment during the year of commissioning ($t = 0$). The same $OpEx_t$ levels used and extrapolated for the analysis described above were applied, and finally, $DecEx$ values were derived from the decommissioning provision. These assumptions result in the following equation for the LCoE:

$$LCoE = \frac{CapEx + \sum_{t=1}^{T} \frac{OpEx_t}{(1+RoC)^t} + \frac{DecEx}{(1+RoC)^T}}{\sum_{t=1}^{T} \frac{EP_t}{(1+RoC)^t}} \tag{3}$$

Thus, the results reflect the LCoE for an OWF commissioned in the respective year in the UK. Figure 4-5 shows a large variation in specific CapEx and DecEx within the OWFs under consideration, which again confirms the reasonableness of the applied approach of modelling each OWF individually instead of feeding a model with averaged values.

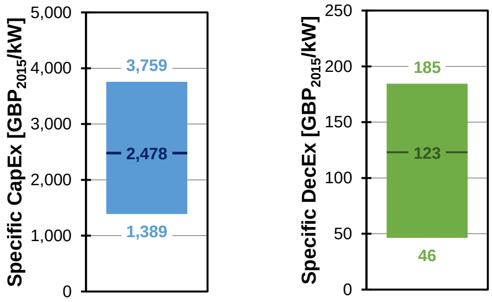

Figure 4-5: Variation in specific CapEx and DecEx values.

It should be mentioned that there is criticism concerning the suitability of LCoE for evaluating variable renewables such as wind because it does not contain variability and integration costs (see [44,45] for a detailed discussion). However, the objective of this article is to assess the real profitability of offshore wind and provide a review of an already implemented support scheme. LCoE, as a widely used metric, seemed to be most suitable for this.

2.4 Data

Table 4-1 provides an overview of the 14 OWFs considered and the number of full operational years for which financial data from annual reports were available. To ensure reasonable results from the extrapolation, only OWFs commissioned before the beginning of 2012 were considered, and thus, for each OWF, data of at least three operational years were available.

No.	Name	Ref.	Round	No. of turbines	Installed capacity	Full operational years with data available
1	Barrow	[46]	1	30	90 MW	8 (2007-2014)
2	Burbo Bank	[47]	1	25	90 MW	7 (2008-2014)
3	Gunfleet Sands I	[48]	1	30	108 MW	5 (2010-2014)
4	Gunfleet Sands II	[48]	2	18	64.8 MW	5 (2010-2014)
5	Inner Dowsing	[49]	1	27	97.2 MW	5 (2009-2013)
6	Kentish Flats	[50]	1	30	90 MW	8 (2006-2013)
7	Lynn	[49]	1	27	97.2 MW	6 (2008-2013)
8	North Hoyle	[51]	1	30	60 MW	10 (2005-2014)
9	Rhyl Flats	[51]	1	25	90 MW	4 (2010-2013)
10	Robin Rigg East	[52]	1	30	90 MW	3 (2011-2013)
11	Robin Rigg West	[52]	1	30	90 MW	3 (2011-2013)
12	Scroby Sands	[53]	1	30	60 MW	9 (2005-2013)
13	Thanet	[54]	2	100	300 MW	3 (2011-2013)
14	Walney	[55]	2	102	367.2 MW	3 (2012-2014)

Table 4-1: OWFs considered in the analysis. [56]

3 Results

Due to the policy of not publishing financial information about individual offshore wind farms, the results of the analysis, as shown in Figure 4-6, are provided in the form of exponential regression lines. It should be kept in mind that the results show the initial trend of the result parameters in the UK up to the year 2012 and a cumulative installed capacity of 1.7 GW, which is one-third of the present capacity. In relation to the learning-by-doing concept that was first introduced in [57] and that describes the process of productivity increases and cost reductions through the accumulation of experience, the results are plotted principally subject to cumulative installed capacity (bottom horizontal axis) and secondarily subject to the year of commissioning (top horizontal axis). [58] The results of the analysis for the base case, i.e., revenue and OpEx are extrapolated with the rate reflecting the inflation, indicate a decreasing trend of the return on capital and a rising trend of the LCoE using the resulting return on capital as a basis. As a benchmark, the LCoE calculated with an interest rate of 10% is also plotted.

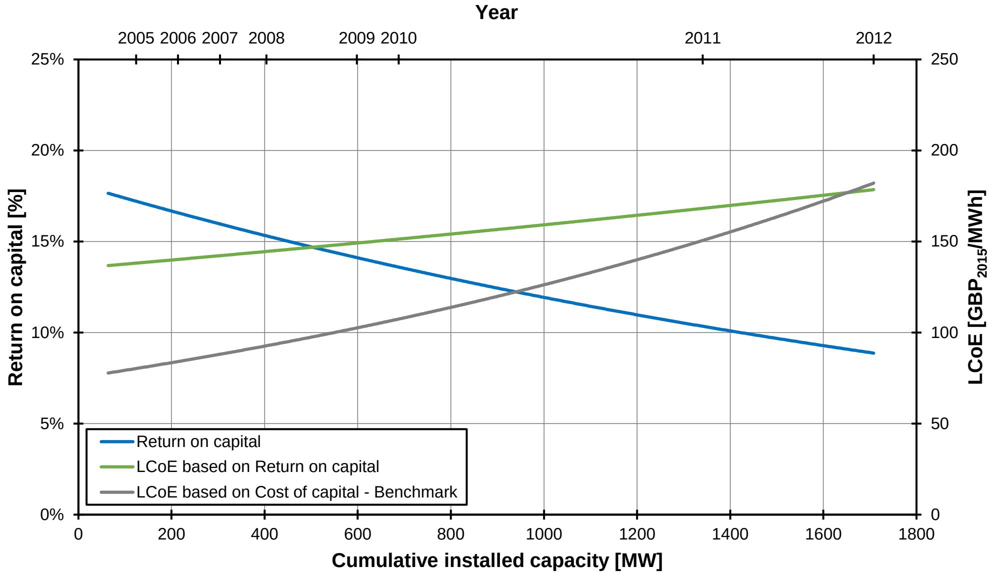

Figure 4-6: Resulting return on capital and its impact on LCoE for the base case.

The assumptions used for the simulation necessitated a sensitivity analysis in order to investigate the robustness of the results. Figure 4-7 provides the absolute deviation of the base case results, which were obtained by applying a varying annual rate of revenue decline and OpEx decrease, respectively, in addition to the already applied inflation rate. The sensitivity analysis shows the expected strong impact of variations in revenue on return on capital and thus on LCoE as well. Furthermore, it shows that the LCoE is rather independent of variations in OpEx because its direct effect on the LCoE is compensated by the consequential counter-effect on the return on capital.

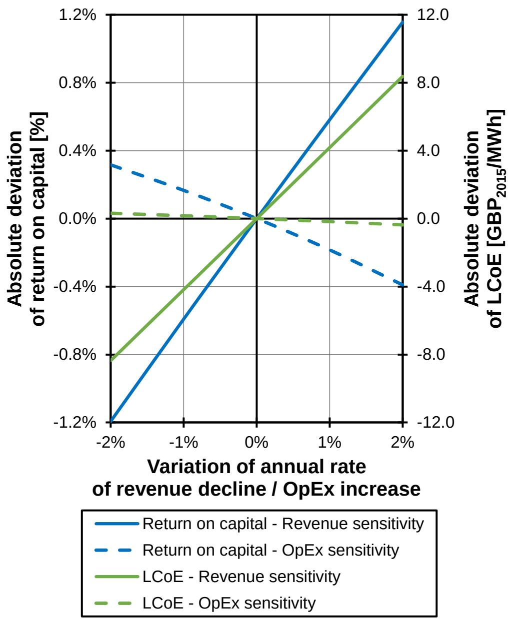

Figure 4-7: Result of sensitivity analysis.

Interestingly, the sensitivity analysis revealed an issue that is likely to emerge in advanced operating years of the first installed OWFs as a consequence of the immaturity of the technology deployed in the early stage. Reducing (increasing) the annual rate of revenue decline (OpEx increase) to a greater extent resulted in an operating loss, i.e., the sum of OpEx and depreciation exceeds revenues in later operating years. This would result in continued operation being unprofitable and calls into question whether the OWFs will reach their planned lifetimes of 20 years. This issue was also the reason why the sensitivity analysis was only performed for a small range of +/- 2% because higher (lower) rates would have falsified the results. On that account, Figure 4-8 provides the result of a “stress test”, where the annual rate of revenue decline (OpEx increase) was gradually reduced (increased) with the aim of assessing the number of OWFs that would experience an operating loss before the end of their lifetimes.

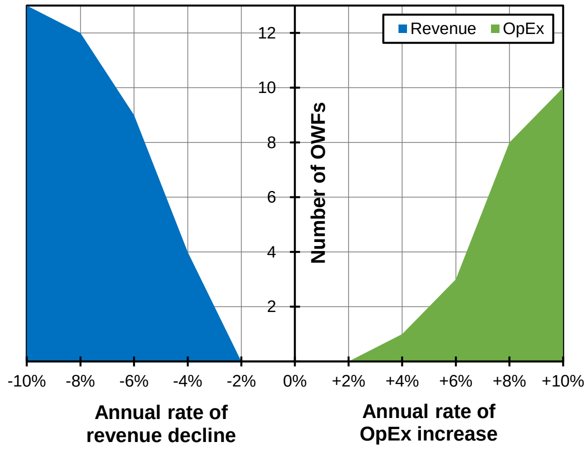

Figure 4-8: Results of the “stress test” – the number of OWFs experiencing an operating loss before their end of lifetime occurs, subject to a decline (increase) in the annual rate of revenue (OpEx).

4 Discussion

Figure 4-6 reveals that the subsidy scheme rewarded entities that risked investing in offshore wind at an early stage and thus a technology that was rather immature at this point in time with a return on capital of more than 15%. At first glance, this seems to be fairly high and it could be argued that entities were overpaid by the subsidy scheme. However, considering that the cost of capital is currently estimated to be in the range of 10–12%, as mentioned in the introduction, it seems reasonable that entities required at least a return on capital in the range of 15% for an investment in the first years of expansion. Furthermore, the decreasing trend shows that the more maturity was gained, thus reducing the risk of investing in an OWF, the less return on capital was offered by the subsidy scheme. One reason for this might as well be the rising LCoE in this early stage of deployment as already reported in other publications (e.g., [1,4,14]) and justified primarily with the additional effort due to increasing distance to shore and water depth. It is also worth noting that the resulting return on capital of individual SPVs does not include the risk inherent in project development, i.e., not all projects are actually realised. All of these aspects, coupled with the fact that the targeted rapid expansion of offshore wind has never stopped and such investments have been considered attractive for years in the UK [25,26], which means that entities were always offered enough incentive, indicate a well-designed subsidy scheme that kept the profits of investing entities within an acceptable range. Apart from that, considering the impact of the assessed return on capital on the LCoE that is revealed by the difference to the plotted benchmark shows that studies using a simplified interest rate of 10% significantly underestimated the LCoE from the first OWFs.

The results of the stress test allow, on the one hand, the conclusion relevant to energy policy that even though the RO subsidy scheme will expire soon, it is important that the price of ROCs is sustained at a reasonable level for the OWFs deployed to this point. On the other hand, the results show that the rapid expansion of a technology that was rather immature might avenge in the coming years. This is most likely considering the possible impact of the assessed average annual rate of increase in OpEx of 6.5% due to additional maintenance effort caused by wear and tear that was not considered in the base case and the fact that any unforeseen expenses were not included in the extrapolation.

Finally, it is worth to compare the presented approach with a simple discounted cash flow model as employed in other publications. Indeed, applying a basic IRR calculation to a cash flow consisting only of CapEx, OpEx, DecEx and revenues results in lower values (average absolute deviation of 2.5% in the base case), which means that omitting financing structure, taxation and accounting in the model underestimates the profitability and thus the return of investing entities.

5 Conclusion

The novel approach of using financial data from the annual reports of 14 early-stage OWFs in the UK as a basis and individually simulating their profitability for the entire lifetime employing a financial model generated reliable results that provide interesting insights. It seems that the price of offshore wind power expansion in the UK was kept within a reasonable range and that the support scheme constituted a good balance between necessary incentive and enforcement of efficiency improvement. Moreover, it has been shown that the interest rate applied when calculating the LCoE, which is a key figure in energy policy debates, has a significant impact on the results and thus should be considered with care. This is why LCoE values that are calculated based on pre-estimated cost of capital may only be appropriate as a basis for the design of a future subsidy scheme. However, the dynamics of the electricity sector now necessitates that the true LCoE, as, for example, for review of the achievement of the 100 GBP/MWh target, are calculated based on the post-assessed return on capital. Apart from that, the results of a sensitivity analysis revealed that a greater reduction (increase) in revenue (OpEx) may lead to an unprofitable operation before the end of planned lifetime, which indicates the importance of sustaining a reasonable compensation level offered by the expiring RO subsidy scheme also for the future. Overall, it may be worthwhile to apply this methodology in the future in order to assess the impact of an already implemented subsidy scheme from a post perspective.

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