Investing in offshore wind energy

Master thesis by

Mathias Frederik Reimich (92636), cand.merc.FSM

Valdemar Ellegaard Stage (92917), cand.merc.FIR

Supervisor

Christian Würtz

Pages

223.499/2275= 98,2 pages

15-05-2019

CBS COPENHAGEN BUSINESS SCHOOL

HANDELSHØJSKOLEN

Abstract

This thesis analyzes how investors should assess offshore wind projects to achieve the best returns. It finds that investors should asses offshore wind projects by combining the knowledge of all the identified key value drivers with the knowledge of the different industry lifecycle stages to enter markets at the optimal point in time and invest in projects with most attractive characteristics according to our key value drivers. To do so, investors should also focus on the support schemes and the inherent trade-off between investing now in a less mature industry with a higher risk and potential return or postponing to invest in a more mature and thus safer market. By doing so, we believe the investor is in the optimal position to achieve the best returns.

It does so through a comprehensive assessment of the key drivers identified in the literature. It uses 449 real-life projects across 16 countries (on 3 continents) and 20 years to analyze the key value drivers, their trends and impact on IRR. This global scope shows that the industry performance develops like an S-curve in different "waves" with a general improvement in performance over time, but with great geographical variance.

For the key value drivers, it find through a multiple linear regression that the most important drivers are respectively: Nameplate Capacity (+), OPEX (-), Capacity Factor (+), distance to shore (-) and depth (-), meaning that the investors should pay greatest attention to these.

Albeit, it does not directly observe the influence that electricity prices (+), CAPEX (-), decommissioning costs (-) and energy loss factors (-) have on IRR these driver all impose great impact on IRR. It test these drivers one by one against IRR and find that Electricity prices have the biggest influence on IRR, followed by CAPEX and lastly the energy loss factor. Furthermore, the thesis finds that the investor should pursue the FiT tariff due to the safety it provides investors.

This thesis contributes to the literature by using "real data" combined with a global scope. This brings a new, unique perspective to future investors.

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1 Introduction

1.1 Background - The offshore wind industry is the subject of this thesis

Rising environmental concerns coupled with growing energy demand has created pressure on society to transit from conventional fossil fuel sources towards renewable energy (RE). In 2018, the EU committed to a goal of 32% of RE supply by 2030[1]. China has committed to a supply of 35-39% by 2024 and other Asian countries such as South Korea and Japan have made similar commitments (Chiu, 2017). Additionally, the first truly global commitment to address the issue of climate change was signed by 185 countries in April 2016, commonly known as the Paris Agreement[2]. To reach these ambitious goals, a massive amount of investment in RE is required. Today more than $280 billion is invested in RE annually, far exceeding the amount invested in fossil fuel power (IRENA, 2017). The investments have accelerated the deployment of RE sources, which has created a virtuous cycle of technological improvements that has increased the cost competitiveness and financial attractiveness of the technologies. Today onshore wind - and solar energy are close to being cost competitive with traditional fossil fuels sources, while other RE sources such as offshore wind energy and hydropower are a bit farther from cost competitiveness. However, offshore wind energy is showing the most promising development and may surpass both onshore and solar energy to eventually become the cheapest source of RE in the future (Lazard, 2018). The rather young nature of the industry coupled with the potential to significantly contribute to the green energy agenda, makes it an interesting and exiting field to examine and the offshore wind industry is the subject of this thesis. To reach cost competitiveness, offshore wind energy needs continuous private investments and therefore, we believe that attention is needed on what drives the value of offshore wind projects from the investor's point of view.

1.2 Problem Identification

As the need for investments in offshore wind energy is evident, we set out to map the development in financial attractiveness of the industry for an investor to understand future trends and learn from history. Throughout our literature review, we have not found any studies doing so and therefore, we believe that this paper, which is based on data from 449 actual offshore wind projects, can establish a "true" picture of the historical development in financial attractiveness across countries. We regard

[1] https://ec.europa.eu/jrc/en/jec/renewable-energy-recast-2030-red-ii 3/3, 12:00
2 https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement 3/3, 12:30

the historical development as key for the investor to understand because countries have entered the industry at different points in time and are therefore at different stages of the industry lifecycle. Therefore, we believe that investors can use the industry development of mature markets to gain an understanding of how premature markets are likely to develop. One investor can learn from another's mistakes and successes and the investor can utilize this if he/she knows about historical trends and how these are likely to influence markets. Therefore, the historical perspective across countries gives the investor knowledge regarding what trends to look for and when to enter a market to achieve the best returns. This is in turn crucial for getting the needed investments in RE and offshore wind energy as highlighted in (Gamel et al, 2016; DEA, 2019).

1.3 Research Question

To contribute to the expanding, complex and increasingly important field of investing in offshore wind energy, this thesis seeks to improve the understanding of which key value drivers the investor should consider in an investment case for an offshore wind energy project.

Our thesis takes the perspective of an investor, but we believe that our thesis also can be helpful for policy makers to make better and more informed political decisions and reach their national RE goals faster and more effectively by facilitating a more attractive investor environment.

We therefore set out to answer the following research question:

How should investors assess offshore wind projects to achieve the best returns?

To answer the research question the following sub questions will be answered:

- *Which drivers are most important for the financial returns and what can be learned from their historical development?*
- *How does support schemes influence offshore wind projects?*

Based on these findings, we will provide investors with recommendations on how to assess the key drivers and what tradeoffs should be considered when investing in wind energy projects.

Our study uses a combination of quantitative data analysis, qualitative assessments of the existing literature and interview with industry professionals to address the research question. The structure of the thesis is outlined below.

1.4 Thesis Structure

This thesis has been structured to create the best foundation for answering the research question presented above. The overall structure of the thesis can be seen below in figure 1-1.

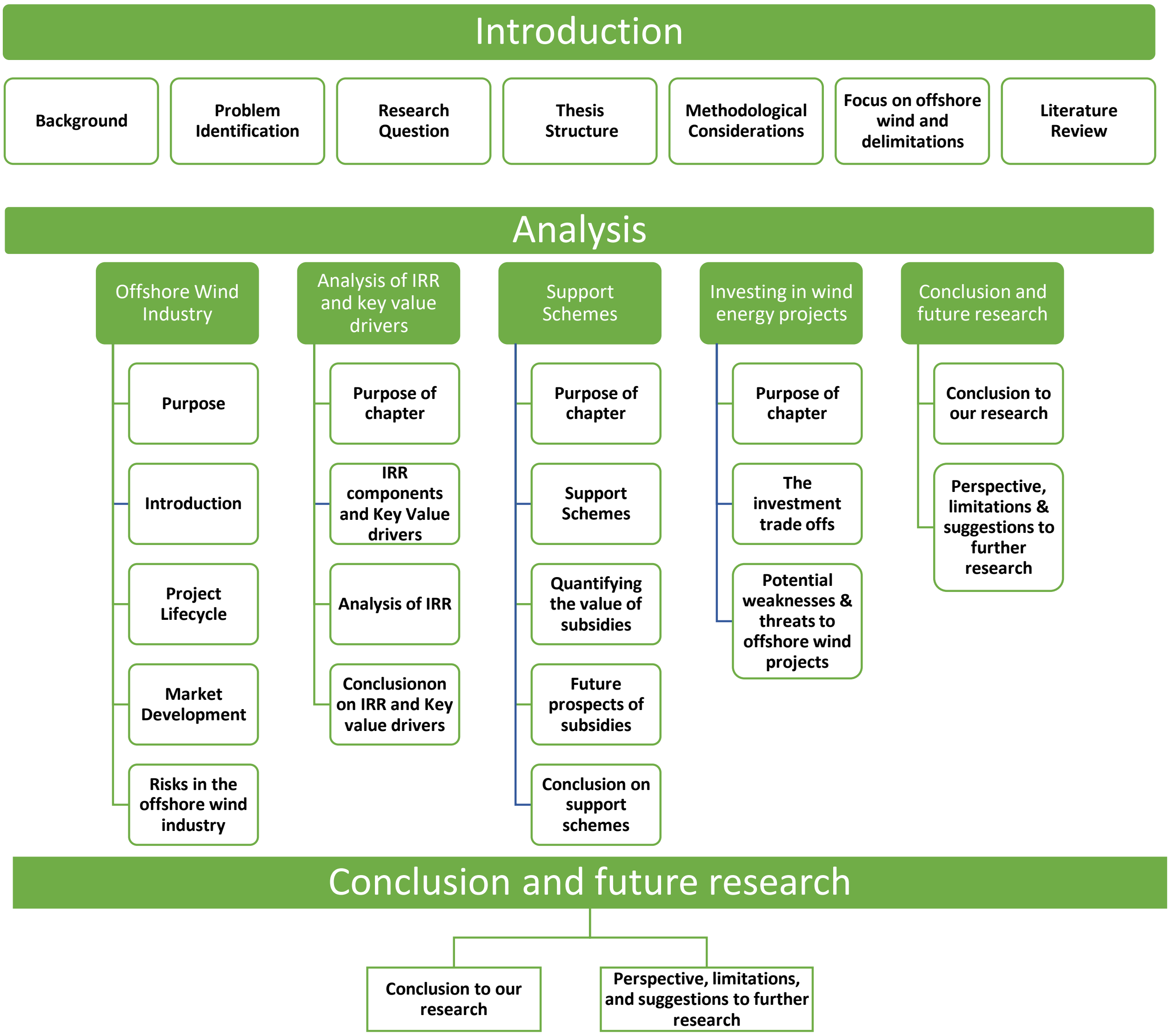


Figure 1-1 Thesis structure

1.5 Methodological Considerations

The main goal of our thesis is to investigate how investors should assess offshore wind projects to achieve the best returns. As we seek to do so by determining and describing why and how different parameters impact project investments, our study will use firstly descriptive method, to describe our data, i.e.. key drivers, and secondly use the exploratory method to explain the relationship between the variables, e.g. how the key drivers impact IRR. In conjunction with these methods and the normative nature of this thesis, we use an inductive approach to answer the research question. This entails that our research question guides us to examine the key value drivers that affect the attractiveness of the investments in offshore wind projects. The thesis seeks to come up with recommendations for investors to consider when investing in wind energy projects. Despite the overall structure being inductive, we do however use the deductive method when we conclude on several of sub conclusions.

To answer the research question, we find it crucial to assess the development in the offshore windfarm industry across countries in the past, present and future to get a comprehensive understanding of a relative young high tech industry. In line with most normative studies, we focus on an evaluation of the present and a projected direction for the future, based on estimates. This scope employs a longitudinal study, that is, that we compare the same data from the same countries over time. This study type is therefore well suited for analyzing change over time, as opposed to cross-sectional studies, where the sample is new for each survey. This gives us the advantage to analyze the trends of the offshore industry (Saunders et al., 2012)

1.5.1 Research Choices and Data Collection

Our study uses a concurrent triangulation method, in which quantitative and qualitative data is converged, through a mixed-method research design, to optimally answer the research question. This method enables us to facilitate, complement and interpret studies, data and findings from more than one perspective to generate greater diversity of views and triangulate findings (Saunders et al., 2012). The quantitative part of our analysis is first-hand data where the qualitative part is second-hand data collected through a combination of literature reviews, interviews with industry professionals and searches in databases. The most important databases used is this study is The Wind Power Net (www.thewindpower.net) and The Global Wind Atlas (www.globalwindatlas.com) which are used to obtain information on the 449 different parks in our dataset. Furthermore, we use the databases RES Legal and The International Energy Agency to get information about the support schemes in our focus countries. We use various websites to obtain the historical electricity prices for our focus countries such as Statista and EURO STAT. Other than that, we use various reports from organizations like IRENA, Deloitte, BVG Associates, REN21, IEA,EEA, DEA and Lazard. Further, we use scientific papers from sources such as ScienceDirect and JSTOR.

Due to the rapid development in the offshore wind industry, publications of data quickly becomes outdated. Therefore, the most recent publications have received the most attention, but it has also been beneficial to include older publications and studies to show the development over time.

1.5.1.1 Interviews

Two semi-structured exploratory interviews have been conducted with industry professionals from PensionDanmark and Ørsted over the course of the research period. These interviews provided real life insights into how investors establish the investment cases. For both interviews, we provided the interviewees with a list of questions focused on what the key value drivers for the investment case were according to them. Other than that, the interviews were very loose in terms of structure, which allowed the conversation to take organically form, which was beneficial to jointly expand and develop the interview. The interviews were recorded and the mp4 files has been uploaded with the thesis. Since the interviews are quite long (approximately 1 hour and 1.5 hours), we have provided a summary of both interviews which can be found in appendix A.1 and A.2.

1.5.1.2 Data Validity, Reliability and the Potential of Biases

Much attention has been devoted to verifying data and to assess the credibility of sources before including them in our studies. Since much of the analyzing element of this thesis is built on data from the sources mentioned in section 1.5.1, we have found it absolutely essential to be critical of our sources and devote time to ensuring that the data is correct and up to date.

Special attention has been payed to The Wind Power Net and The Global Wind Atlas since they provide most of the data for our quantitative analysis. The Wind Power is the largest global database on wind projects and contains data on 659 offshore projects and 19.688 onshore farms across 121 different countries. The website contains information on such things as the developer, the manufacture, the turbine, the location of the site, project start, distance to shore and sea depth. These are all essential factors for a correct IRR calculation why it is essential that the data is correct. According to the website, all data is checked and revised over a rolling period of six months. However, to ensure that the data was correct, several random samples were taken and reconciled to other sources. As an example, data from the website was held against the data provided by the prospect for the projects Horns Rev 1 and BARD Offshore 1. In both cases the data was valid. Further, several high profile stakeholders pays a subscription fee for the use of the database. Therefore, we deemed it reasonable to conclude that the data from the website was highly reliable.

The Global Wind Atlas is an online database developed through a partnership between the Department of Wind Energy at the Technical University of Denmark (DTU Wind Energy) and the World Bank Group (consisting of the World Bank and the International Finance Corporation (IFC)).[3]

[3] https://globalwindatlas.info/about/introduction 10/3 15:15

The website has been developed to help policymakers and investors identify potential high-wind areas for wind power generation virtually anywhere in the world. By entering the latitude and longitude of the location of the wind farm, the website uses advanced mathematical modelling to calculate the wind speed and the capacity factor[4] for the different turbine classes that exists. This was confirmed in a telephone interview (not recorded, summary in appendix A.3) with Jake Badger, head of wind resource assessment modelling at DTU who was responsible for developing the database. The data from the website is considered highly reliable since it is used for global investors to assess the attractiveness of project sites[5]. Furthermore, the website was established through a collaboration between DTU Wind Energy and the World Bank Group, which are some of the leading industry experts.

RES Legal and the International Energy Agency are also considered highly reliable sources as they were founded on the initiative of the European Commission[6] and the International Trade Agency[7]. Since the websites are databases of law implementations, we do not see any reasons why the data should be biased in any way.

For the various websites and reports used, we recognize that potential bias can be present. However, since we compare the findings from several different sources we believe that this bias is eradicated. For example, in deriving our CAPEX costs, we take data from several reports and use an average in our analysis.

1.5.1.3 Data Collection

As previously stated, we obtain information on the projects from the database ***The Wind Power Net,*** one of the largest global databases on offshore wind projects[8]. As previously stated, the website contains information on 659 offshore wind projects including developer, the manufacture, turbine, the location of the site, project start, distance to shore and sea depth. See uploaded Excel-file, sheet “DATA”. We want to extract all this information for every offshore project in the website and to avoid timely manual work, we use “python programming” to extract the data from the website. The code can be seen in appendix Figure 8-12. The website organizes the parks in according to the country in which the park is located. Therefore, we set the code to loop through each country in the database, click on offshore projects and copy/paste all the information into an excel sheet. However, the website

[4] An expression for the % time during a full year that the windmill is operational
[5] https://globalwindatlas.info/about/purpose 10/3 15:15
[6] http://www.res-legal.eu/about-res-legal-europe/ 12/4 09:30
[7] https://www.iea.org/about/ourmission/ 15/4 17:30
[8] https://www.thewindpower.net/index.php 10/3 15:15

fails to account for certain revenue and cost input parameters such as wind power, Capacity factor, CAPEX and OPEX that we need for our valuations.

To get the wind data, we use the website www.globalwindatlas.com. We simply insert the location of the projects (latitude, longitude) into the search field and obtain the corresponding wind speed and correlating capacity factor. This is explained further in 3.2.1.3.

The costs parameters are derived from literature comparisons. Various reports exist on the historical and forecast cost development of the offshore wind industry. Data from these reports have been collected and compared to create the data points used in our valuations (see Figure 8-1 and Figure 8-2). Since the reports states costs at different point in time and different currencies, all values have first been inflation adjusted to 2019 prices in the respective local currency and then converted to US dollars using the exchange rate from 10-04-2019. Cost are reported as dollars/kW or /mW.

Below we present a table to give an overview of the central data sources and where we use it.

Data source	Data Usage	Section
www.thewindpower.net	Characteristics of wind projects (Name, Location, Size, project start	No specific section
www.globalwindatlas.com	Wind conditions (Capacity factor) for all wind projects	3.2.1 Revenue
https://www.iea.org/policiesandmeasures/renewableenergy/ http://www.res-legal.eu/search-by-country	Support Schemes for EU, US and Asia	4 Support Schemes
https://www.ceicdata.com/en/china/electricity-price https://www.eia.gov/totalenergy/data/annual/showtext.php?t=ptb0810 https://www.moeaboe.gov.tw/ECW/english/content/ContentLink.aspx?menu_id=154 https://www.oeb.ca/rates-and-your-bill/electricity-rates/historical-electricity-rates https://www.statista.com/statistics/263492/electricity-prices-in-selected-countries/ https://ec.europa.eu/eurostat/web/energy/data/database	EU, US and Asian electricity prices	3.2.1 Revenue
Various organizations and peer reviewed reports	CAPEX and OPEX	3.2.2 Cost

1.6 Focus on offshore wind and delimitations

This section presents the scope and delimitations that has been made to optimally answer the research question.

1.6.1 Focusing on offshore wind

Our thesis considers the value drivers for investment in offshore windfarms, which is a sub segment of wind power energy under the broader field of renewable energy. To provide the reader with a broad picture of the scope, we have provided a breakdown of the industry in the figure below. To ensure that the proportionate context is clear to the reader, we have added the relative shares for each layer of the breakdown where possible:

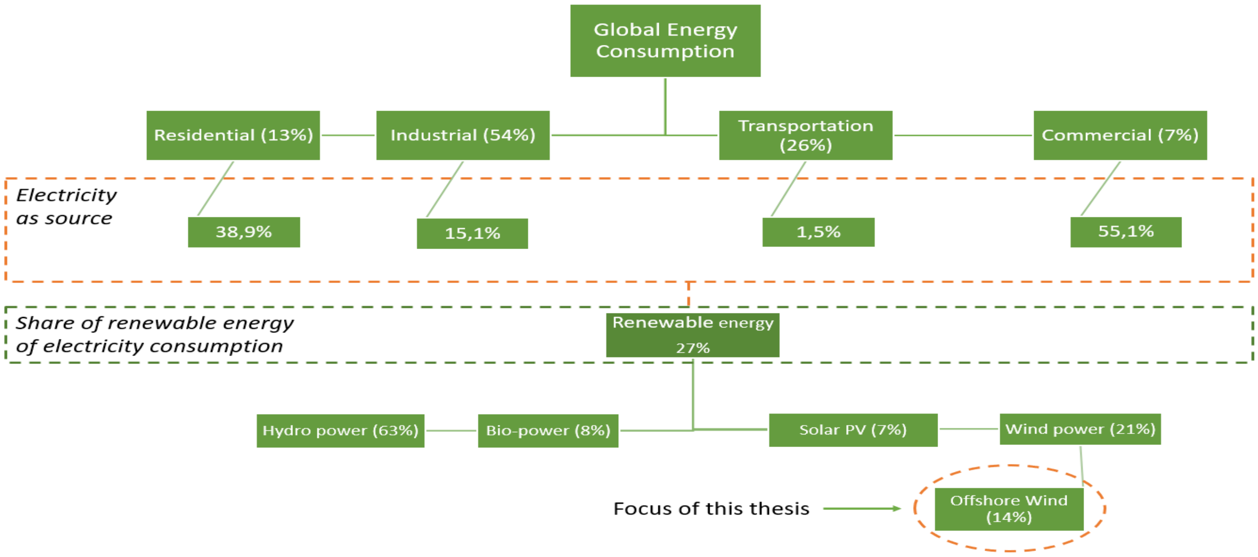


Figure 1-2 Own creation, sources: IRENA 2017

As seen from the figure above, wind energy composes approximately 21% of the market for renewable energy where offshore wind energy constitute approximately 14% hereof. This corresponds to 0,8% of the world's electricity energy consumption (27%*21%*14%). Wind energy is the second largest renewable energy market mainly driven by onshore wind projects. However, offshore wind projects are still a relatively new and small field. As explained in section 1, the young and promising nature of the industry is exactly what makes it exciting and relevant as an investment opportunity. Other renewable energy sources will receive little attention in this thesis. In reality, investors will compare the expected return of different investments and choose the one that gives the highest return (Brealey, Myers, & Allen, 2014). Institutional investors and banks have often allocated funds for investments in renewables because of the steady, predictable returns and the goodwill from the public (Wind Europe, 2017). This means that if investing in offshore wind energy becomes less attractive, it can drive investors towards other renewable technologies such as solar – or geothermal energy and vice versa. However, including other technologies would give too broad a scope and would not allow us to go in depth with our analysis.

1.6.2 449 offshore wind parks selected for analysis

To answer our research question, we have collected data for a total of 659 different offshore windfarms, which we narrow to 449 projects as described below.

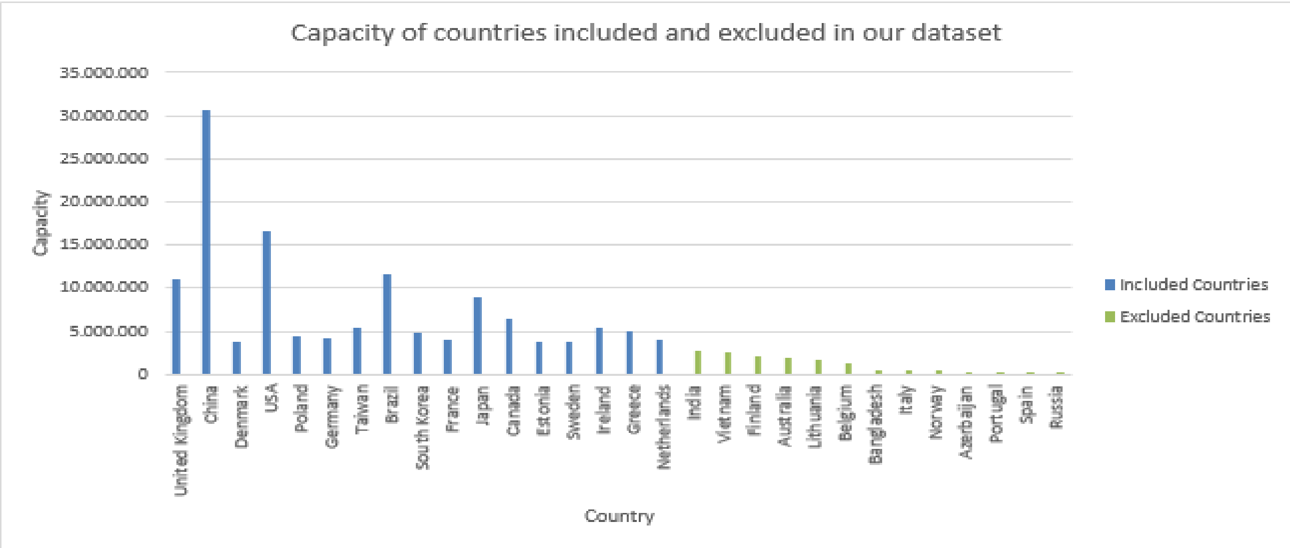
We have chosen to make three central limitations for the projects in our dataset:

1. Size above 15 MW
2. Windfarms after year 2000
3. Projects from 16 key countries

We have chosen to focus on projects above 15 MW, as recommended in our interviews with both PensionDanmark and Ørsted. The rationale is that this thesis takes the perspective of an investor and projects below this size doesn't have the scale to be an attractive investment. Furthermore, trustworthy data is more difficult to obtain for small projects, which would make our calculations unreliable while adding little value to our analysis. This delimitation excludes 131 parks from our dataset.

We have chosen to limit ourselves to windfarms from year 2000 and forward because of data shortcomings. An example of data shortcomings before year 2000 is electricity prices. As will be explained later in section 3.2.1.1.1, the electricity market has historically been organized as state-controlled monopolies until the markets were liberalized during the last two decades. Therefore, electricity prices before year 2000 are not available for many of the countries in our dataset and therefore we cannot calculate the revenue stream. Furthermore, our literature comparisons showed that little research on cost exists from before year 2000, making it hard to obtain reliable data. As such, this was not a delimitation that was initially intended, but one we found necessary during the data collection process. However, we believe that the delimitation adds value to our thesis as it has forced us to focus on the last two decades, which subsequently is the time period in which the industry has flourished. Furthermore, only 8 projects are excluded from our dataset by narrowing our scope to year 2000 and forward, which clearly shows that the industry has taken off in the last two decades. For this reason, we believe that we add value to our analysis by narrowing our focus to the two most central decades of the industry where reliable data can be obtained.

Lastly, we have chosen two focus on 16 countries out of a total of 30 countries in our dataset. This is because 16 countries (marked with blue) comprises approximately 92% of the cumulative nominal power (kW) in the defined dataset and the bottom 13 countries constitutes merely 8% combined. This can be seen below:



By focusing on the 16 countries, we belive that we address our research question better by having a deeper focus on the important countries. Furthermore, having many countries greatly complicates our analysis while adding little value to our findings. As an example, Australia is not included in our dataset because the country has merely 1 windfarm (Star of the South Energy Project) that comprises less than 1% of the total nominal power in the pipeline.

Lastly, we have been forced to remove 10 parks from our analysis because the parks never obtained a positive cash flow, making it impossible to calculate IRR.. The delimitations are summarized below:

Delimination	#Parks
Offshore Wind Industry	659
Size above 15 MW	-131
Project start after year 2000	-8
Projects from 16 key countries	-61
Projects must have at least 1 positive cash flow	-10
Total	**449**

Lastly, it is important to mention that some of the observations are "parts" of a park. For example, the Danish park Horns Rev consists of Horns Rev I, II and III. These will however be regarded as seperate projects, as there exists differences between the parts locations, e.g. the depth, distance from shore and capacity factor. Furthermore, different parts of a park is often owned by different developers and therefore it makes sense to regard them as separate projects (Appendix A.1).

1.6.3 Investor point of view

This paper considers the attractiveness of offshore wind projects from the point of view of the investor, which is important to emphasize since it may influence priorities and hence choice of key value drivers. An investor is profit-seeking, hence the financial value drivers are of greatest importance. Our paper does not take the perspective of a specific investor as we are interested in the “general” value of offshore wind projects. This is one of the main arguments for our choice of a pre-tax-pre-subsidy Internal Rate of Return (IRR) valuation method, as explained in section 1.7.2. This means that an investor cannot use this thesis to calculate the profitability for an individual, particular investment, but rather as a high-level assessment tool for valuation purposes.

1.6.4 Delimitations

In answering the research question “How should investors assess offshore wind projects to achieve the best returns?” we have made the following major delimitations:

- IRR is calculated pretax and pre subsidies
- Use of historic generic prices do not capture project specific differences
- Focus only on offshore wind investments
- Risk quantification is not part of the analysis

1.6.4.1 IRR is calculated pretax and pre subsidies

In our calculations of the IRR for the 449 wind parks across 16 countries over 20 years it has not been possible to get the individual parks specific data with regards to taxes and subsidies. Therefore we have calculated and analyzed the IRR pretax and pre subsidies. Acknowledging that taxes and subsidies are very important for an investor in the offshore wind industry, we have in chapter 4 analyzed tax and support schemes applicable for offshore wind projects for our focus countries.

1.6.4.2 Use of historic generic prices does not capture project specific differences

In chapter 3– we describe the assumptions for the various components included in the cash flow model used for calculating the IRR. For several of the components we have used historic generic prices (i.e.. measured by USD/kW) from the literature as it has not been possible to get prices for each individual project. Therefore, our calculations cannot say anything about the specific return of the individual projects, and as we, for all projects regardless of their capacity size use the same cost per unit, we cannot derive any information of economies of scale. We do however use site specific depth, distance to shore and capacity factor, which are important drivers for the IRR calculations.

1.6.4.3 Focus only on offshore wind investments

The focus is only on offshore wind investments and potential better alternative investments in energy technologies like e.g. sun, hydro, nuclear, etc. or in other industries do not receive much attention. As our research solely focuses on the financial return we do not consider any other potential incitements for investing in offshore wind energy. Due to the climate awareness on could argue that there is a pressure on investors to invest in offshore wind projects despite delivering returns below what they would normally accept if they were acting as a purely financially driven investor.

1.6.4.4 Risk quantification is not part of the analysis

The offshore wind industry is facing several major risks related to the technology, construction, operational, volume and price fluctuations, finance and political changes (European Commission, 2019). As these risks may be substantial, they have been described but not quantified in section 2.5.

1.7 Literature Review

The purpose of this literature review is to show where our research places within the existing literature and hence our contribution to the body of literature in the field of offshore wind energy. In this review and throughout the thesis, the term "literature" refers to all publications, peer reviewed papers, journals, market reports, and research by any constituency pertaining to the industry, regardless of role and intended audience.

1.7.1 General

This section will serve as a general introduction to the existing literature on offshore wind projects. The focus is on the broader industry trends and how investors should valuate offshore wind projects.

With the rapid development of wind energy in the last decades, the body of literature and research has increased significantly. This is undoubtedly related to the rising focus on limiting greenhouse emissions, which has gained attention from both the general population, scholars, organizations, the politicians, and subsequently investors. Since its commercial takeoff in the 1980's, the energy industry has experienced a stable and steady growth. In 1991 the first offshore pilot project was initiated in Denmark called "Vindeby", with the ambition of bringing parks away from land to make them bigger and more efficient. In the years to follow, parks were established in pioneer countries such as Germany, The UK and Denmark and a wide spectrum of research and publications spurred.

The spectrum stretches from deep technical reports from e.g. DTU Wind Energy Campus Risø, broad industry reports from IRENA, investor specific report from Wind Europe, forward looking analysis from both public European institutions, industry specific consultants like BVG Associates. Most of the independent scientific research published in peer reviewed papers has been centered on macro implications and trends, such as political, environmental, societal or industrial. Ryan et al (2019) analyses the environmental impact of offshore wind farms. Li and Xu (2019) investigates the political and societal impacts of offshore wind energy. Dedecca et al (2016) looks at the different marketing strategies to develop the adaptation of offshore wind farms. The research focusing on the financial aspect of wind projects are found to be either case-specific or based on hypothetic examples. For example, Gamel et al (2016), Judge et al (2019) and Scwanitz & Wierling (2016) all analyze the financial value of an actual investment case and Ioannou et al (2018) uses a hypothetic wind project to assess the impact of different value drivers. In reviewing the literature, we have found little research combining the learnings over time and across geographical areas. Heptonstall (2017) analyzes the development of CAPEX over time and Prässler and Schaechtele (2012) analyzes the development of IRR (including subsidies) over time.
Therefore, we believe that there is room in the literature for analyzing the influence of the key value drivers for the 449 offshore wind projects in our dataset over time based on real data from the projects. This is the central distinction between our work and that of Prässler & Schaechtele (2012).

To ensure that we are analyzing the right value drivers, we have searched the literature to find consensus about which factors that affect the value of projects. On a macro scale Ydersbond and Korsnes (2016) highlights "greater climate awareness and reduction of local pollution, improving energy security, and creating jobs and boosting economic growth through high-tech leadership" as the main drivers for political investments in wind energy. As such, the macro scale value drivers are the reason why the industry is developing at rapid speeds as countries have committed to national RE goals that they must meet through investing. On a project specific level, the drivers are consistently: the electricity prices, nameplate capacity[9], energy loss factors, the wind resource, subsidy schemes, CAPEX, OPEX, decommissioning costs and financing costs (Deloitte, 2015; Barroso and Balibrea-Iniesta, 2014; Keles et al., 2013; Mytilinou et al., 2018; Dicorato et al., 2011). These are the value drivers that we analyze and test against IRR in chapter 3. We devote a separate chapter to subsidy schemes (chapter 4).

[9] Industry expression for the size of the park often measured in Megawatt

1.7.2 Valuation Review

Looking into valuation methods used in the literature for assessing investments real options (RO) and discounted cash flows (DCF) / Internal rate of returns (IRR) are most commonly used.

1.7.2.1 Real Options (ROs)

The advantage of the RO approach is that it includes and quantifies uncertainties in projects. Kozlova (2017) examines the existing literature on renewable energy project valuations and finds 101 peer reviewed papers, of which wind energy is covered in almost 50%, recommending the use of RO as the valuation method. Furthermore, Kozlova (2017) finds that of the 101 papers 48% addresses the electricity price, 23% the technology, 21% production, 18% fuel price, 15% project value and 12% subsidy schemes as the modelled uncertainty in the papers RO valuation.

As RO requires a lot of data which we do not have access to and as RO calculations are very time consuming when you have 449 projects, we do not consider RO as the optimal valuation method for answering our research question. Furthermore, in both our interviews with industry professionals (see Appendix A.1 and A.2), we were told that they had never seen real option valuations used for investment assessments.

1.7.2.2 Internal Rate of Return (IRR)

Another approach is to assess an investment by analyzing the investments cash flow to calculate the discounted net present value or the internal rate of return (IRR) that the investment delivers. For our offshore wind projects cash flows can be prepared based on the information we have collected from our various data sources making the IRR method very suitable for our analysis. Therefore it has been selected as our valuation method.

The IRR is computed by solving for the discount rate that sets the projects Net Present Value (NPV) equal to zero (Hillier et. al, 2011). As such, the formula can be shown as following:

$$IRR = NPV = 0 = \frac{CF_1}{(1+r)^1} + \frac{CF_2}{(1+r)^2} + \cdots + \frac{CF_n}{(1+r)^n}$$

Where the cash flows of the projects are calculated and then the IRR is found by solving the equation for r. We do this using the “IRR” function in Excel.

A setback of the IRR method is that it does not take project size into account. Two projects can have the same IRR, but if the project sizes are heterogeneous then the projects will have different values to the investor.

1.7.3 Contribution to the literature

As stated in section 1.7.1, the literature on offshore wind projects have developed with great speed since the industry was pioneered in the 90's. The spectrum of research has developed in vastly different directions, but the research on the financial aspect is most central to review for our paper. In this regard, we observe that most of the literature looking at financial attractiveness and value drivers are either case-specific i.e. a single valuation or uses hypothetical projects to take a more quantitative approach. Therefore, there is little research that applies a broad scope to real-life cases like we have do with 449 different real-life projects. Additionally, there is little research combining the learnings about the value drivers across time and geographical areas.

We have neither found any studies that simultaneously considers the national differences in the attractiveness of support schemes and the attractiveness of the wind project. As stated in 1.7.1, the studies we have found has done one or the other, which we find rather surprising since much of the literature points to the fact that the support schemes is a key value driver.

Therefore, we believe that our study contributes to the emerging literature in three ways:

1. We combine the learnings across time and geographical areas
2. We use 449 real-life cases to get a more realistic picture
3. We combine project value drivers with the value of the subsidy schemes

The historical perspective across countries gives the investor knowledge regarding what trends to look for in order to achieve the best future investment. Since our study is global and includes the Asian and North-American market, we believe that we cover the global trends and industry development more accurately, which also is something not done before.

Furthermore, since we use real-life cases to assess the key value drivers of the investment case, we obtain a more accurate picture than previous studies that have used hypothetical wind parks. As such, the way in which we calculate the pre-tax-and-subsidies IRR is not new to the literature, but the fact that we do it for 449 real-life projects in different countries from 2000-2020 has not been done before. It allows us to analyze global and national trends in the development of project-specific value drivers in an accurate manner since we consider real-life cases. Furthermore, it allows us to use multiple linear regression to effectively rank the value drivers according to their influence on the pre-tax-and-subsidies IRR. Lastly, our analysis of the support schemes allows us to show the whole picture of what an investor should look for, where previously studies have mostly either considered the project-specific drivers or the subsidy schemes. By combining our knowledge of the industry trends, pre-tax-and-subsidies IRR and subsidy schemes we can say something about the trade-off that investors face when investing in offshore wind projects. More on this in section 5.2.

2 Offshore Wind Industry

2.1 Purpose of this chapter

The chapter starts with an industry overview that briefly describes the industry followed by a description of the project lifecycle and support schemes. The purpose is to give the reader an overview of the industry's development and briefly show the project lifecycle to illustrate the uniqueness of the heavy upfront investments. Finally we will touch upon the risks inherent in the industry.

2.2 Introduction

The offshore wind industry was "born" in 1991 with the project in Vindeby, Denmark. Vindeby was a 5 MW wind farm with 11 turbines. To illustrate the rapid development of the industry, the biggest turbine produced today has a nameplate capacity of 9.5 MW, that is, for 1 single turbine. The biggest park currently being built is Hornsea 1 in UK, which will be 1.218 GW and will distribute power to 1 million UK homes[10].

When the offshore wind energy industry was pioneered in the 90's, it was an industry dominated by a few large conglomerates from the energy sector (Wind Europe, 2017). As industry evolution theory predicts (Grant, 2016), more players started to enter the market as prove of concept was established and the industry gained legitimacy (Kaldellis & Zafirakis, 2011). The last decade has seen heavy growth, process innovation and cost optimization and many scholars have compared the offshore sector with the closely related onshore sector, which is now one of the most cost efficient RE sources (Irena, 2017; Lazard, 2018). However, the offshore industry has the potential to develop much faster due to the knowledge overlaps from the onshore sector. For example, the engineering behind efficient turbines is not particularly different for an onshore and offshore park, meaning that most of the innovation in the value chain benefits both industries (Krohn, Morthorst, & Awerbuch, 2009). The main difference between the two sectors is the deployment of offshore windfarms, which is the main challenge to the offshore industry. It is currently very expensive to install offshore windmills since you need to lay foundations and cables on the ocean floor connecting the park to the grid (Snyder & Kaiser, 2009). The maintenance costs are also greater due to the harsher conditions and difficult access to the windmills (Deloitte, 2011). However, the earning potential is also significantly higher

[10] https://orsted.com/da/Media/Newsroom/News/2019/02/The-worlds-biggest-offshore-wind-farm-Hornsea-one-generates-first-power 18/3 10:45

due to better offshore wind conditions and since it is possible to establish bigger parks with larger turbines thus benefitting more from economies of scale (Esteban, Diez, Lopez, & Negro, 2011).

2.3 Project lifecycle

The market for offshore windfarm consists of a supply side in the form of national states that offer concessions in competitive bidding rounds and a demand side in the form of project developers who bid on the projects[11]. This means that no windfarm is established without the direct involvement of the state and therefore an increase in supply is always driven by political ambitions (Deloitte, 2011). If the developer wins the bidding round, they will enter the development phase. The process of developing offshore wind projects from initiation to the farm is fully commissioned typically takes 4 years where approximately 80% of the total lifetime costs are capitalized. This makes it the riskiest phase and the point in time where the financing needs are at their highest. Risks are especially cost overruns and financing problems (Deloitte, 2015). Institutional investors associate the phase with excessive risk and usually doesn't invest at this point in time (see appendix A.2). The development phase is followed by the operational phase, which lasts between 20-30 years, whereas an average of 25 years is commonly used in the investment case (appendix A.1 & appendix A.2). The park generates a stable cash flow since the revenue is predictable and the costs of keeping the park operational are low. The revenue generated from the park decreases slightly as the turbines gets worn down, estimated to be 0,5% (BVG, 2011; appendix A.1). Furthermore, parks are typically commissioned with some sort of support scheme that creates an attractive case for investors. There are significant variations in support schemes across countries, but the commonality is that they create revenue certainty thus reducing the project risk. Unfortunately for investors, they typically expire after a predetermined eligibility period or after the windfarm has generated a certain amount of MW energy (Lewis & Wiser, 2007). This leads to a reduction in the cash flow and increases the project risk in the last years of the operational phase. Lastly, the park is decommissioned which entails a decommissioning cost (Deloitte, 2015).

Below we have illustrated the project lifecycle by the net cash flows (excluding subsidies) for a random project from our dataset.

[11] A right granted by the government to develop a windfarm on public territory

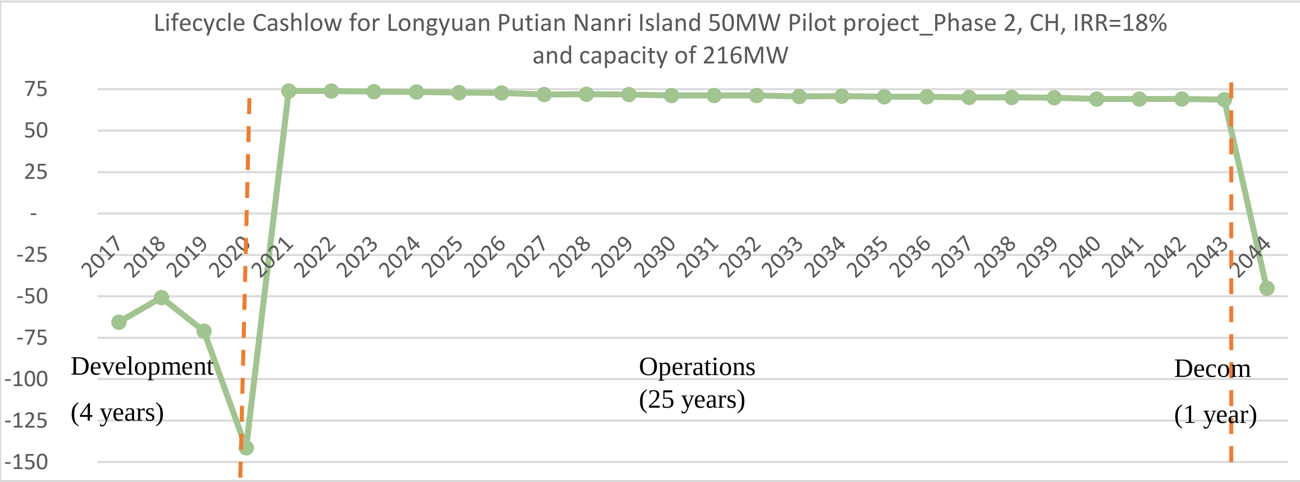


Figure 2-1 Lifecycle cashflow of park

As we can see, the development years are characterized by significant negative cash flows due to the CAPEX costs, followed by a stable cash flow that decreases slightly until the decommissioning phase.

The CAPEX is distributed as follows: year 1: 6%, Year 2: 10%, Year 3: 34% and Year 4: 50% (Fei, 2017).

2.4 Market development

In this section, we seek to give the reader an overview of the market development for the 16 countries in our dataset. The graph below shows the distribution of commissioned projects and projects in the pipeline for our 16 focus countries measured in capacity amount. As we can see, the country with the largest amount of commissioned capacity is currently the UK (20 GW) followed by China (13 GW) and Germany (Approx 9,8 GW). The other 13 countries are fairly equal in the amount of commissioned capacity with the US currently ranking in last place. However, when we consider the pipeline capaciy, we see that China current has has the highest amount (approx 20,6 GW) closely followed by the US (20,2 GW), which corresponds to 24% and 23% of the total pipeline capacity. This is followed by the UK (14,3 GW), which corresponds to 16% of the total pipeline capacity. As such, three markets combined constitue approximately 63% of the total pipeline capacity.

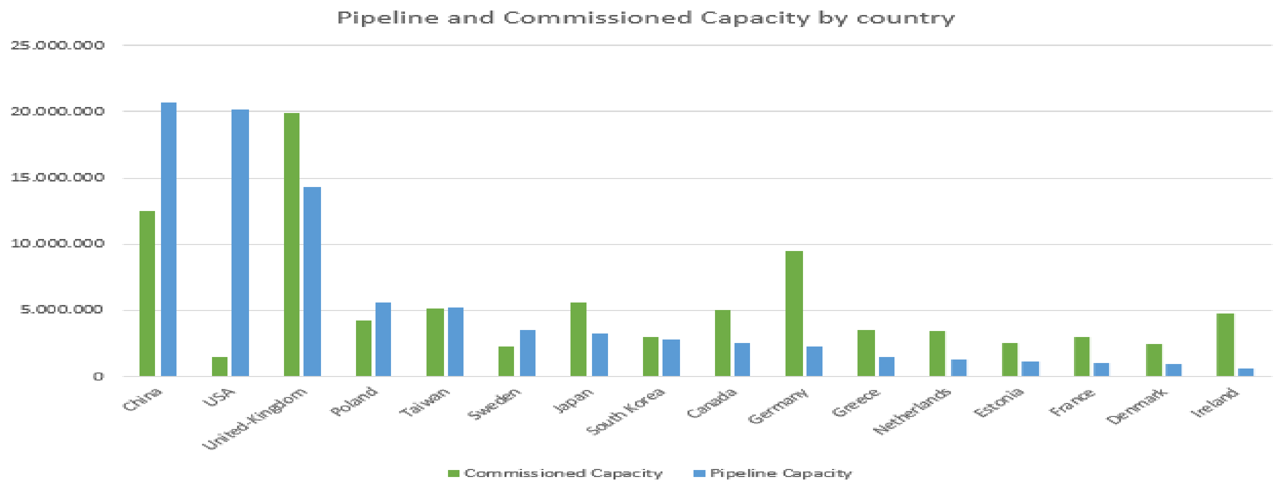


Figure 2-1-Distribution of commissioned and pipeline projects

The country with the fourth largest pipeline capacity is Poland with 5,6 GW, which corresponds to 6% of the total pipeline capacity. From here on, the amount of pipeline capacity is fairly equally distributed with a decreasing trend where we see France, Denmark and Ireland in the bottom three. As such, we clearly see that three countries are responsible for most of the total market growth. However, these are also large countries (especially China and the US) who naturally will have a higher energy demand and thus, all else equal, need to develop more parks to meet their RE goals. For this reason, it makes sense to look at the relative deployment of pipeline capacity to asses the growth in each market. Relatively speaking, the US has the highest market growth by far since approximately 93% of the country's total capacity is in the pipeline. This is followed by China with 62%, Sweden (61%), Poland (57%), Taiwan (50%) and South Korea (49%). This tells us that even though three countries are responsible for most of the total market growth, relatively speaking, we see a lot of growth in most of our focus countries. This indicates that new markets are emerging. Lastly, we see that mature markets such as Germany and Denmark have some of the lowest market growth. To summarize, we identify three trends from the graph:

1. Most of the total market growth comes from the China, the US and the UK
2. The relative market growth is high in most of the focus countries
3. Mature markets such as Denmark and Germany has little market growth

These findings matches those of Credit Suisse (2018) who in their global report concludes that most of the market growth is expected to come from China, the US and selected European countries. However, the analysis above, does not consider the development in number of initiated projects over time. This is shown in the graph below:

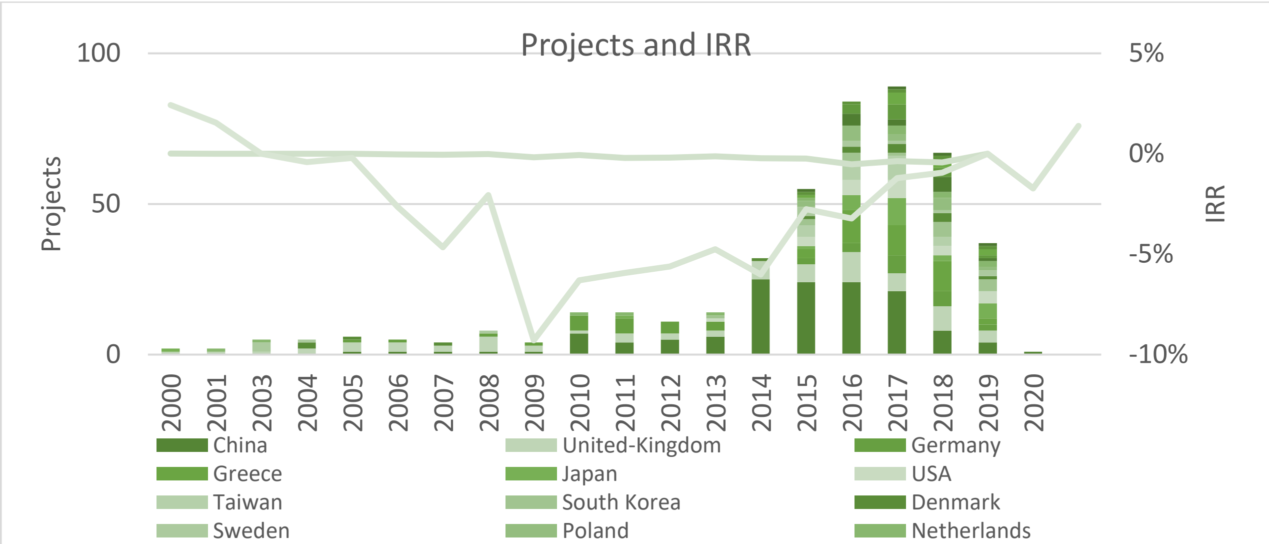


Figure 2-2 Number of projects and IRR over time – Own development based on 449 offshore parks

The graph shows that the number of initiated projects was relatively stable from 2000-2013 with a slightly increasing trend. Hereafter, initiated projects took off. The number of initiated projects more than doubled from 2013 to 2014 and increased by 40% from 2014-2015. We also see a major increase the following two years followed by a global peak in 2017. Hereafter, the number of initiated projects has decreased with a fairly high amount. However, we believe that the low amount of projects in 2019 and 2020 can be explained by the fact that the projects have not been tender offered by governments yet. Therefore, the numbers are distorted and when the dataset is updated in the future, we expect to see a much higher number of installed projects in these years. However, the decrease from 2017-2018 is unexpected given the expectations to the industry. Credit Suisse (2018) and Lazard (2018) also forecast with a slight growth decrease from 2017-2018. Both explain this as market saturation in the German market followed by an increase in growth in Asia and the US.

Additionally, the IRR is plotted along the number of projects to highlight one of the main limitations of the data set, which is a left skewed distribution. 92% of all projects are found in years 2010 to 2019, which corresponds to 70% of the total installed capacity. This creates some interpretation challenges that should be noted. First off, when interpreting the IRR for a general trend over time using multiple linear regression, it should be noted, that there exists no statistical significance for the first 9 years because of the small sample size here (n=37). As such, we can use the data from these years to explain the trends in the industry, but not to say anything significant about the IRR in this specific period. However, when the observations are used in conjunction with the rest of the dataset, they increase the explanatory power of our model. Therefore, they should not be excluded from the model. More on the multiple linear regression in section 3.3.4.

The key take away from the above is:

1. Initiated projects were relatively stable from 2000-2013 (slightly increasing trend) where they took off until 2017 where the deployment started to decrease. However, the decrease in deployment is mainly seen because projects have not been commissioned for 2019/2020 yet
2. We do not have a statistically significant number of projects from 2000-2009 to say anything general about the IRR in this period. However, we can use the projects to illustrate the trend in the industry and they increase the explanatory power of our multiple regression model when used in conjunction with the rest of the dataset

2.5 Risks in the offshore wind industry

This section will map out the main risks faced by an investor in the offshore wind industry. The purpose is to give an understanding of what risks there exists and how investors should hedge them (European Commission, 2019).

Table 2-1 Risk in the offshore wind industry

Risk	Source of risk	Risk Driver	Potential hedge
Technological Risks	• The risk of owning an obsolete technology	• New technologies	• Compatibility with new models
Construction Risk	• Supplier too slow • Technical issues in construction phase	• Counterpart not delivering • Exogenous events	• "Turnkey projects" • Assessment of counterpart
Operational	• Risk arising from operations, can be either internal (human errors) or external events (nature caused)	• Technical failures • Extreme weather	• Insurance • Train staff
Volume	• Unanticipated variations in the power supply (wind) or demand	• Variations in wind • Overall global consumption changes	• Sell to interconnected grid (i.e.. other countries)
Price	• Changes in prices will lower the revenue • Changes in price of other sources	• Supply/demand change	• Use Power Purchase agreements to fix price

Financial structure*	• The risk of being short of financial resources; i.e.. getting sufficient funds to invest/built and maintaining funds in the treasury medium and long term	• Unexpected costs to set off financial structure	• "Over" financing of projects to secure against "a rainy day"
Political/subsidy risk	• Changes in public policy, i.e.. taxes or subsidies policy • Protectionist policies	• Changing governments • New technologies	• Work towards being independent of subsidies

*not in scope of this thesis

The risks above serve as a starting point for investors. As the focus of this thesis is to assess how investors can get the best return when investing in offshore wind industry, we delimit from looking more on how to mitigate or hedge against these risks.

3 Analysis of IRR and the key value drivers

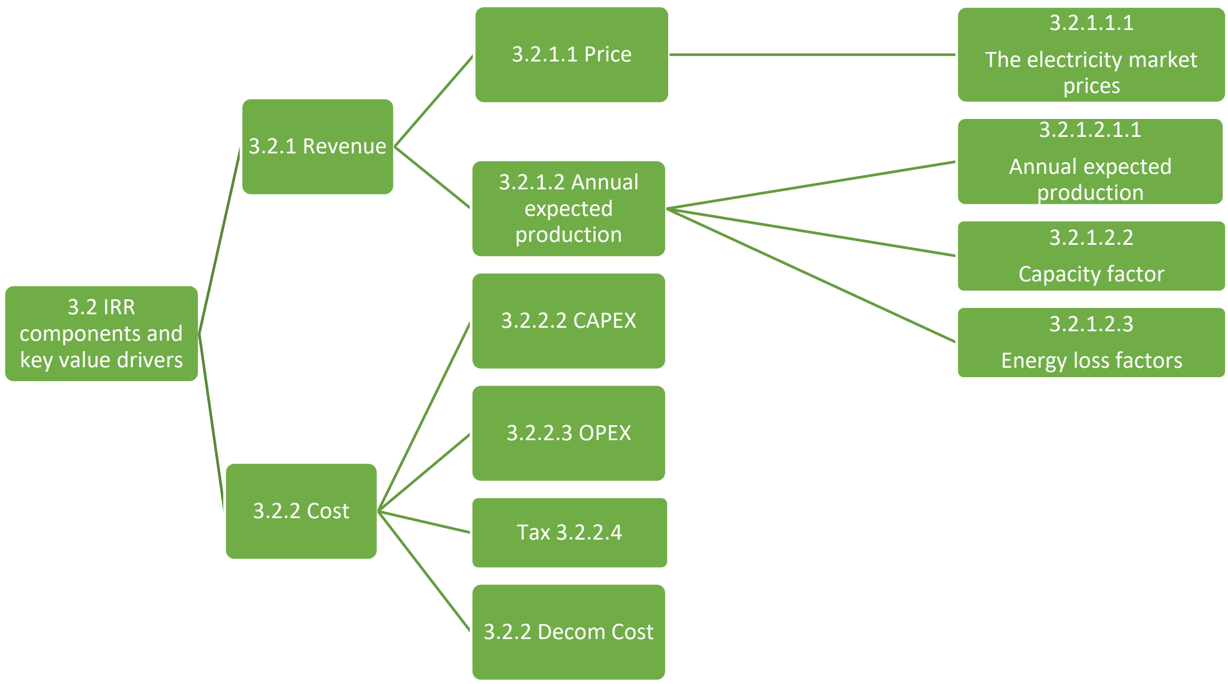
3.1 Purpose of this chapter

The purpose of this chapter is to answer the first sub-question: *Which drivers are most important for the financial returns and what can be learned from their historical development?*

We assess how the value drivers can be calculated and how they impact IRR. For revenue we will analyze price and annual production hereunder nameplate capacity, capacity factor and the energy loss factor. For cost we will analyze: CAPEX, OPEX and decommissioning costs. This is then compiled in an analysis of IRR where we consider how the various value drivers has affected IRR over time and how geographical differences impacts IRR. The chapter is structured as following:

- Assessment of the pre-tax and pre-subsidy IRR components and key value drivers for the 449 projects
- Combined analysis of pretax-and-pre-subsidy IRR for the 449 projects in relation to the key value drivers over time

The calculation of the pre-tax and pre-subsidy IRR for the 449 projects is based on the following model:



For each of these components, we will for the offshore wind industry find relevant information to be used for the calculation of the pretax-pre-subsidy IRR. Furthermore, each of these components can also be understood/seen as a value driver and the potential impact are discussed. A summary of the assumptions made in our cash flow model including the pros and cons can be found in

Table 8-11.

3.2 IRR components and key value drivers

Based on the literature review in section 1.6.3, this chapter will analyze the identified key project-specific value drivers shown above. Based on the calculations, we arrive at the pretax-pre-subsidy IRR values for our focus countries in the 20 year period (2000-2020) that are shown in Figure 3-18.

The point is to identify what these value drivers actually entail, how they are calculated and their influence on the investment case. The chapter is structured such that we first analyze the value drivers in regards to the revenue and then costs. We examine the characteristics of the drivers, how they should be assessed by the investor and how they impact the Pretax-and-pre-subsidiary IRR for our 449 projects. Afterwards, we use country-specific examples to analyze the IRR and the key value drivers in the respective countries.

3.2.1 Revenue

For investors, it is critical to attain a comprehensive understanding of the factors driving the revenue from an offshore windfarm in order to assess the financial attractiveness of a project. This section will be structured as how revenue is calculated: Price*Quantity, which in the following sections will be decomposed, for an investor to fully understand. We do however acknowledge that support schemes are revenue drivers, but we will not consider these in this chapter as they require their own independent assessment. These will be assessed separately in chapter 4.

3.2.1.1 Price

The electricity price is obviously an essential component for calculating the revenue of a windfarm and thus a critical value driver for investors. Modelling the volatility of electricity prices is essential for capturing the true risk/return profile of projects, but evidence today suggest that many investors often do not account for the volatility, but rather tend to assume a constant price marked up with inflation over the lifetime of projects (Deloitte, 2015). The importance of electricity prices to the investment case depends on the support scheme since many projects are tender offered with a power purchase agreement (PPA) for a predetermined time, which limits their market exposure until the agreement expires. Due to the long project lifetime discussed in section 2.3, the investor needs to forecast the electricity prices far into the future to obtain an insight into their projected earnings. This is naturally associated with a great deal of uncertainty, which could explain why many investors tend to take a "short-cut" and discount a constant price with the expected inflation rate to arrive at the future price. In the section to follow, we examine the electricity market and the characteristics of electricity prices in order to arrive at the best method for forecasting electricity prices. Using this method, we forecast the electricity prices of our 16 focus countries and then we test the electricity prices influences on IRR for the 449 projects in our dataset. We do not take the price influence of support schemes into account as these are reviewed separately in section 4.

As such, the section is structured as following:

1. Examination of the electricity market and the characteristics of electricity prices
2. Identify the optimal forecasting method and apply it to the countries in our dataset
3. Test the impact of electricity prices on IRR
4. Discuss the unique characteristics of electricity prices in relation to forecasting models
5. Discuss the future of the industry and how the changes will influence the forecasting methods

3.2.1.1.1 The electricity market prices

Historically, the energy sector in most countries were organized as regulated monopolies, with prices based on the social – and industrial policies of governments. The market players were vertically-integrated companies that had exclusive rights to supply electricity to consumers within a given area (Joskow, 2008). High operating and construction costs coupled with high retail prices and more efficient generating technologies, stimulated pressure for changes that would reduce electricity costs and retail prices. Therefore, it was decided to bring in the private sector to provide better incentives for controlling construction - and operating costs and encouraged innovation in power supply technologies (Joskov & Schamelensee, 1998). The liberalization started gradually in the 1990's when the European electricity sector underwent a significant degree of privatization. The European Community launched directive 96/92 EC to improve competition in the sector and to break up monopolistic structures. This led to an increase in trade, which spurred the founding of power exchanges and market operators to organize this increase in trading (Mayer, Schmid, & Weber, 2011). The liberalization meant that the services provided by the incumbents were unbundled leading to a dis-integration in the supply chain. Furthermore, prices went from being centrally determined to being determined by market forces (Joskow, 2008).

As such, the main take away from the above is that following the market liberalization, electricity prices went from being centrally controlled to being determined by supply/demand. However, forecasting electricity prices is different from that of other commodities due to the unique characteristics of the commodity. Electricity cannot be stored in an economically feasible way, which means that the commodity must be sold and consumed immediately upon production. This can also result in severe mismatches between supply/demand, which can cause price spikes and drops (El-Hawary, 2017). Energy from fossil fuels and nuclear power plants is continuously available for conversion into electricity, meaning the supply is directly controlled and can be increased/decreased to meet demand. However, energy sources such as wind and solar are "intermittent", meaning the energy is not continuously available, hence outside the direct control of developers. If the wind conditions are not optimal during high demand periods, windfarms can potentially miss out on tremendous revenue streams. On the other hand, if the wind blows excessively in low-demand periods, the windfarm will be forced to either sell the electricity at a discount or shut down (Albadi & El-Saadany, 2010). This sometimes results in negative electricity prices when the low demand experiences a supply shock due to unexpected high electricity transfers from intermittent energy sources such as windfarms (Mayer, Schmid, & Weber, 2011). This is called "the intermittency problem" and possess a risk outside the direct control of operators (Breeze, 2016). Therefore intermittent energy sources pose limits to the grid since we need energy sources that are continuously available for conversion into electricity to meet demand (Welch & Venkateswaran, 2009). Since the production is outside the direct control of the generators, there is an extra uncertainty in correctly forecasting the revenue stream for intermittent energy sources. The key take-away for the reader is that electricity prices are harder to forecast and much more volatile than other commodity prices due to the non-storability and the intermittency effect.

3.2.1.1.1.1 Forecasting electricity prices

Following, the characteristics of electricity prices stated above, our literature review reveals that scholars point to three characteristics that a forecasting model must take into account (Borenstein & Holland, 2003; Colmenar-Santos Et al., 2014; Conejo Et al., 2005; Nogales Et al., 2002; Mayer Et al., 2011). These are:

1. Seasonality
2. Volatility
3. Mean-Conversion

These characteristics will be reviewed one by one in the subsequent sub-sections.

3.2.1.1.1.1.1 Seasonality

The demand for electricity follows strong seasonality at the annual, weekly and daily levels. The annual seasonality's is strongly correlated to weather patterns. For example, the demand for electricity on the northern global hemisphere is higher in the winter due to the necessity to heat up homes (Credit Suisse, 2018). Weekly seasonality is related to consumption in work days vs. weekends. Consumption is much higher in business days than weekends, since many businesses are closed on weekends. Lastly, seasonality on the daily level is related to the lifestyle of most humans. Electricity consumption is high during the daily hours and very low at night when we sleep (Conejo, Contreras, Espínola, & Plazas, 2005). What level of seasonality needs to be considered, depends on the time horizon of the forecast. Market operator's needs to know the demand down to the daily, hourly and even minute basis to accurately set the prices to meet demand (Borenstein & Holland, 2003). However, investment profitability analysis should not be concerned with the daily or weekly prices since investors are interested in the total project value. Forecasting to such depths adds little value to the investment case while adding a lot of complexity. Therefore, it can be argued that investors should exclude short-term seasonality from electricity forecasts when establishing the investment case. However, as a park operator, it makes sense to calculate revenue/costs monthly (hence forecast monthly prices) in relation to month-end closing of books. Therefore, once a park is owned, more thorough forecasts may be beneficiary. Following the argumentation above, our forecasts will not take seasonality into account.

3.2.1.1.1.1.2 Volatility

As previously stated, the volatility of electricity prices is caused by the non-storability of electricity coupled with the necessity to maintain supply/demand on a constant basis. Since electricity supply is neither stable nor completely predictable, supply is not always able to follow demand, which causes volatility (El-Hawary, 2017). Severe price spikes[12] are sometimes observed if sudden supply/demand shocks such as unexpected high electricity transfers from intermittent energy sources takes place. This sometimes results in negative electricity prices when the demand is simultaneously low. Since the production and subsequently electricity transfers from intermittent energy sources are unpredictable, the volatility in electricity prices are also difficult to predict. As stated in section 3.2.1.1, RE projects are often commissioned with a power purchase agreement for a predetermined

[12] Price spikes are characterized as a large short-term deviation from a specified reference value

time period. Whenever the market price is lower than the price guaranteed by the power purchase agreement (which it is most of the time), the difference is made up from the renewable energy surcharge (REG), which the states pay to the sellers of RE. As the market price approaches zero, the difference payable via the REG surcharge increases and therefore increases the cost born by the governments and subsequently the consumers. Therefore, the mismatch between supply/demand is often not a problem for RE producers, but instead a burden born by the end-consumers. Furthermore, due to political ambitions, renewables have priority in most power grids and therefore always comes first in the merit order[13]. This means that intermittent energy sources can be a challenge to the grid since the supply from these energy sources is unpredictable and cannot be regulated to follow the demand. Following the argumentation above, our forecast needs to account for the volatility. Following the argumentation above, our forecasts needs to take the random volatility of electricity prices into account.

3.2.1.1.1.1.3 Mean-Conversion

When abnormal demand causes electricity prices to increase, producers are incentivized to increase their production to take advantage of the higher prices. This puts a downward pressure on the price and as demand returns to normal levels, generators turn down their production. The opposite is true when prices fall. Therefore, electricity prices are said to have a mean-reverting nature caused by the free market mechanisms. However, the speed of the mean reversion differs substantially. When huge spikes occur, the prices tend to reverse much faster than when normal spikes appear (Conejo, Contreras, Espínola, & Plazas, 2005). Therefore, a mean-conversion factor should be included in the forecast, but the use of a single mean reversion factor can result in too slow a removal of ‘extreme’ price movements (spikes) and too fast a removal of normal price movements. This problem can be solved by separating the mean-conversion factors for the ‘extreme’ and the ‘normal’ price movements (Benth et al., 2003). However, since the mean-conversion follows the seasonal price movements, it can once again be argued that this level of complexity is irrelevant for the investment case. Therefore, we only conclude one mean-conversion element to take the yearly mean-conversion into account.

3.2.1.1.1.1.4 Forecasting Methods

As previously stated, the market for electricity was recently liberalized, which makes it a younger research field than price forecasting of other commodities. However, the field has received a lot of attention in the recent years due to the importance of ensuring balance between supply and demand

[13] https://www.cleanenergywire.org/factsheets/why-power-prices-turn-negative 2/4 11:15

in the power grid. Several studies such as Wilkens & Wimschulte, (2007); Redl et al., (2009); Botterud, Kristiansen & Ilic., (2010) have addressed the question of how electricity prices are formed in the market and various approaches has been proposed. The primary difference between the market pricing mechanisms for electricity prices and other commodities is the common occurrence of price spikes. This is at least partly a consequent of the non-storability of the product and the unpredictability of the supply that can lead to severe mismatches between supply/demand (Conejo, Contreras, Espínola, & Plazas, 2005). The predominant part of research focuses on short- and medium-term forecasting of prices, i.e. monthly, daily or even prices on a minute basis, but as stated in the previous section, we are interest in yearly prices. Therefore, we will not go as far in-depth as much of the literature and exclude factors such as seasonality and second-order mean-reversion.

Having established the characteristics of the market and the time horizon of the analysis, the next section uses these findings to arrive at the optimal forecasting method.

3.2.1.1.1.1.4.1 The Wiener Process

The price spikes are extremely difficult to forecast since they are determined by somewhat random events such as supply variation. Therefore, it is common practice to use a stochastic process to account for the randomness of the price movement (Nogales, Contreras, Conejo, & Espinola, 2002). The Wiener Process, also known as a Brownian motion is a stochastic process that captures the randomness of electricity prices over time (El-Hawary, 2017). The model states that the price change can be described by a “memoryless” normal distributed random variable at time t. The model assumes that price changes are uncorrelated over time, hence have no long-term trend. The model is useful for capturing the somewhat random volatility that characterizes the market but fails to account for the mean-reverting element. The model can be expanded with a drift factor to better capture the long-term trend in electricity prices. However, a drift factor entails that prices exhibit a long-term trend meaning that long-term forecasts will wander far from their starting point (Barndorff-Nielsen & Shephard, 2001). If the long-term trend is positive, it would mean that electricity prices in later years will be significantly higher than in the past. This would mean that projects that are commissioned in later years, will receive a much higher valuation for the wrong purposes. Therefore, a drift element will give biased valuations and a mean-conversion element seems to be more appropriate. Therefore, the model needs to be expanded to include a mean-conversion element.

3.2.1.1.1.1.4.2 Orstein-Uhlenbeck Process

One model that captures the mean-conversion element is the Ornstein-Uhlenbeck process (Barndorff-Nielsen & Shephard, 2001). Mathematically, the process can be described as:

$$dx = \eta * Exp(\bar{x} - x)d_t + \sigma dz$$

Where η indicates the speed of the return of the mean value, $\bar{x}$ indicates the long-term mean, i.e.. the price that the future price x converts to. Dz is a Brownian motion and σ indicates volatility in the form of standard deviation. As such, the process can be broken into two components:

1. $\eta(\bar{x} - x)d_t$
2. σdz

The first part of the equation is the mean-converting element, which is found by taking the difference between a future price and the long term mean and multiplying it with the speed of return. The speed of return η is an important factor, as it needs to capture the mean-converting property of electricity prices. The second component captures the random volatility of electricity prices by multiplying a Brownian motion with the standard deviation of the historical variance. With the above argumentation, it can be concluded that the Ornstein-Uhlenbeck process captures the most important characteristics for long-term electricity prices; mean-reversion random volatility.

3.2.1.1.2 How electricity prices are calculated

In this section, we use the knowledge derived above to forecast the electricity prices for Danish windfarm “Aflandshage”, which is the principal example throughout this chapter.

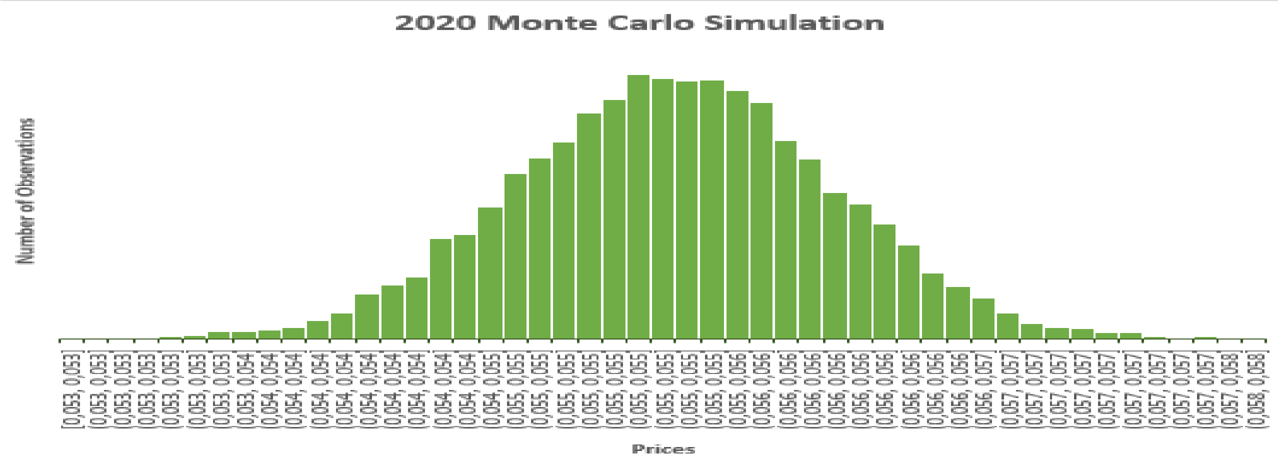
Since the Orstein-Uhlenbeck process uses a historical mean and variance combined with a mean-reverting element and a Brownian motion to predict future prices, we use historical electricity prices going back to year 2000 to calculate the historical mean and variance.

First, the historical, nominal Danish electricity prices are derived from the database. Using the method described in 1.5.1.3, we convert the prices to 2019 USD prices. We then calculate the historical mean and variance of the prices. The historical mean is the value that the future prices reverts towards with speed of return “η”. As previously stated, the speed of return is an important input factor as it needs to capture the mean-converting property of electricity prices. A maximum likelihood estimation technique that minimizes the error given by the difference between the real price change and the one that the model predicts is used to determine the speed of return. First, we compute the historical yearly price change as $P_{t+1} - P_t$. We then calculate the price change that the Orstein-Uhlenbeck model would have predicted with a random value for η. Hereafter, we can calculate the historical predictive error as the difference between the real price change and what the model predicted. We can now compute the degree of mean-reversion used in our model by solving for the number that minimizes the model's predictive error. This is calculated to be 36,11%. Now we need to incorporate the random volatility using a Brownian motion. The Brownian motion is calculated in Excel using the "Normsinv(Rand())" function. The "Rand()" function calculates a random number from 0 and 1 and the "Normsinv" function takes a fraction between 0 and 1 and calculates how many standard deviations you need to go above or below the mean for a cumulative normal distribution to contain that fraction of the entire population. Therefore, combining these function computes a random number from a normal distribution with a mean of 0 and a SD of 1[14]. This is then multiplied by the long-term, historical volatility to calculate the random element of the electricity prices.

The 2020 price can now be calculated by:

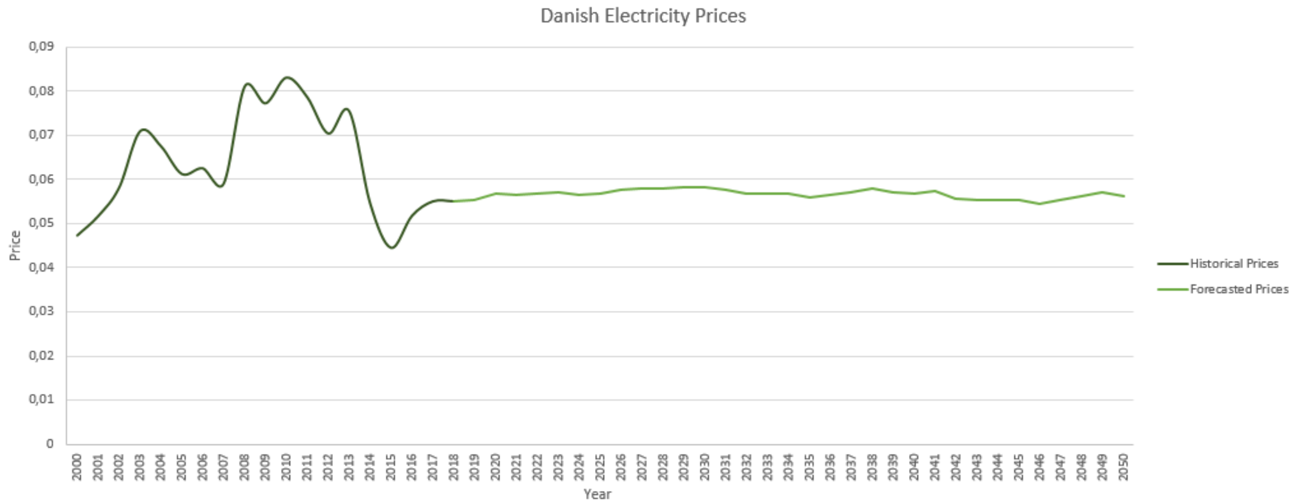
$P_{t+1} = \mathrm{P_t} * Exp(\eta(\bar{x} - x)d_t + \sigma dz) = 0{,}055 * Exp(0{,}3611 * (0{,}0639 - 0{,}055) + 0{,}0117 * Normsinv(Rand()))$ = 0,056

This is done for every year of the operational period. To cope with the random element of our model, we compute 10.000 Monte Carlo simulations for each price forecast. By the law of large numbers, the empirical mean of the simulations is a better approximation of the true value of the random element (Barndorff-Nielsen & Shephard, 2001). We calculate the average price of the simulations, which is the price we use for that year. We get the following distribution



[14] https://www.graphpad.com/support/faq/generating-random-numbers-with-excel/ 25/3 11:30

From which we use the average price of 0,05554 USD/kWh which is our final price. The graph below shows the historical and our forecasted electricity prices for the Danish electricity market:



As it can be seen, the future prices are more stable due to the mean-converting element of the Orstein-Uhlenbeck model and there is much less volatility. Therefore, the model will predict more stable prices than what is likely to be observed in the market in the future why it could be argued that the Orstein-Uhlenbeck process underestimates the yearly volatility.

3.2.1.1.3 Electricity prices impact on IRR

By applying the calculations stated in section 3.2.1.1.2 to the 449 parks in our dataset, we arrive at the following differences in prices:

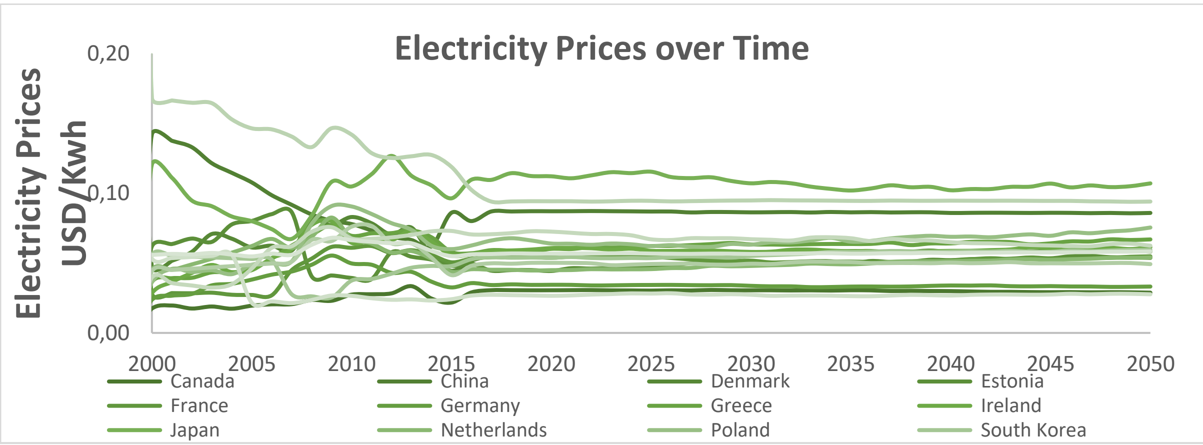


Figure 3-1-Historical and predicted electricity prices

As previously stated, the forecasted prices are much less volatile than the historical observed prices, which causes future cash flows to be overly stable. This is a shortcoming of our analysis. A possible explanation is that our Brownian motion is calculated using the Normsinv(Rand()) function in Excel, which implicitly assumes that the volatility is normally distributed, which is not the case in reality. Our analysis shows that both historically and in the forecasted time period, the Asian markets have the highest electricity prices by far (#1 Japan, #2 Taiwan, #3 China) and the lowest are found in North-America. The European prices are quite equal and located in the middle-segment.

From the graph below, we see that there is a positive relationship between the electricity prices and the IRR. This is logical, since a higher selling price results in higher revenue. The prices below are the average electricity prices pr. Country pr. project. This means that we use one price pr. project instead of using the actual 25 different prices for each project. This gives an idea of how the electricity price level affects the IRR, I.E., higher prices results in better IRR.

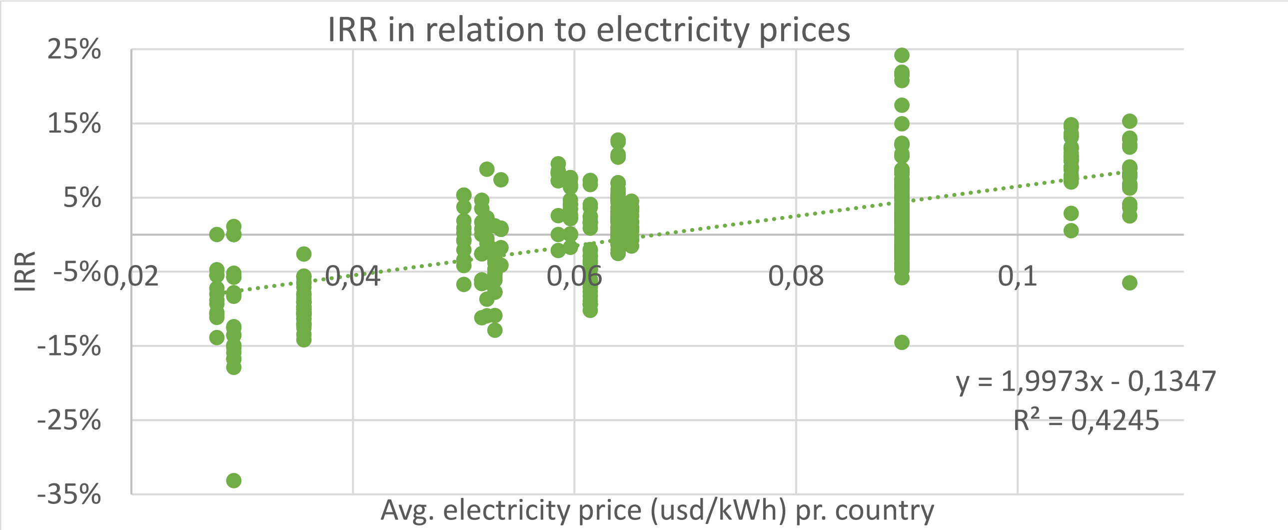


Figure 3-2- IRR in relation to electricity prices

3.2.1.2 Annual expected production

The quantity of produced electricity from a windfarm is the other essential component for calculating the revenue of a windfarm and thus a critical value driver for investors. The quantity of produced electricity is determined by the nameplate capacity, the wind resource at the project site, the classifications of the turbine, the capacity factor and the energy loss factors (Deloitte, 2015). As subsequently shown, the wind resource can be described using a probability density distribution while the classification of the turbine can be described by its power curve. Combining these two with the nameplate capacity allows for estimation of the annual expected production for a park. However, the annual production needs to be corrected for the influence of the capacity factor and the various energy loss factors. As will be shown in section 3.2.1.3, we use a slightly modified method to calculate the annual expected production, because the website windpoweratlas.com allows us to take certain short cuts.

3.2.1.2.1 The wind resource

Without enough wind at the site location, the turbines cannot generate electricity and subsequently not generate a revenue stream. Therefore, identifying the best project-sites is essential for the value of the investment case. There exist great geographical differences in wind quality both on a macro and micro scale. For example, the coasts of northern Europe and the UK are windier than that of southern Europe and Africa, which can explain why the industry is flourishing in northern Europe and not in the south (Appendix A.1). This can be seen in appendix, Figure 8-11. There also exists great difference in the wind quality from land to water. This is because there is not obstacles to "damage" the wind on water which gives more stable and powerful wind. As such, the wind as a resource is a geographical prerequisite for project sites and economical feasible conditions are only found on certain latitudes and longitudes.

3.2.1.2.1.1 Forecasting wind

Investor's needs to forecast wind quality to assess the earnings potential of a site and to identify what turbine would be optimal at the site (Deloitte, 2015). This is an important decision since the turbines are essential for the revenue stream but also the single largest cost component, historically ranking from 30-50% for offshore wind, as discussed in section 3.2.2.2. Common industry practice is to use historical 2-5-year measurements of hourly wind speeds at the location and based on these measurements, create a probability density distribution. This is shown below:

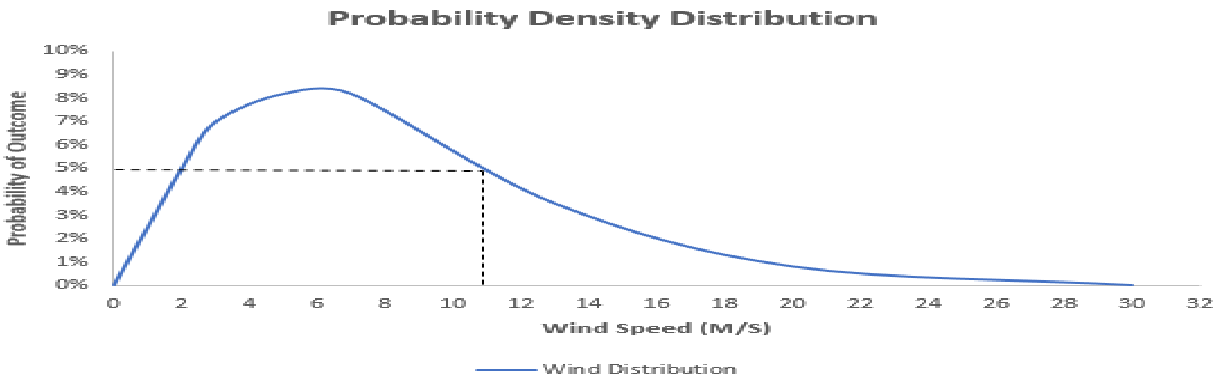


Figure 3-1 Own creation based on Deloitte (2015)

The wind speed distribution curve indicates how often a certain wind speed is observed. For example, the figure shows that the wind speed is around 11 M/S 5% of the time. Since wind studies are done on an hourly basis, it means that the wind speed is 11 M/S $365_{days} * 24_{hours} * 5\% = 438$ hours/year. To assess the wind quality on a high level wind maps like Globalwindatlas.com could be used with advantage, due to its ease of use. The uncertainty of wind speeds can have a significant influence on the revenue in a given period, but the wind variability is uncorrelated over time. Therefore, there is a short-term risk of having a bad "wind-year", but this will be rejuvenated in the long-run. In this context, wind variability is a static uncertainty that is fixed over time (Deloitte, 2015).

3.2.1.2.1.2 The power curve

The relation between wind speed and power output for a turbine is quantified using a power curve. The power curve for a 2.3 MW turbine is shown below:

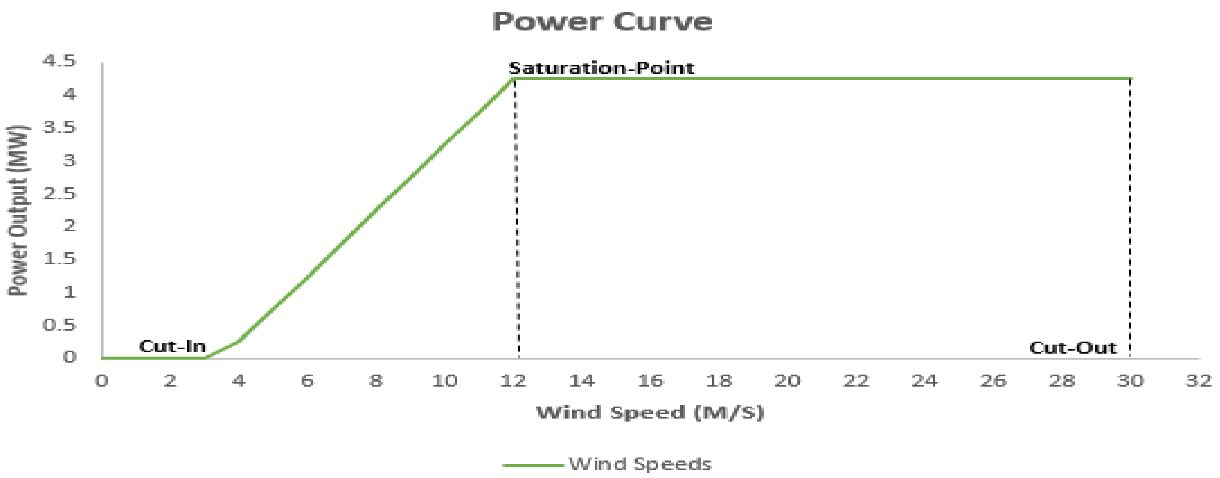


Figure 3-2 Own Creation based on Deloitte (2015)

The power curve shows how much energy the turbine produces hourly at different wind speeds (Boccard, 2009). The power curve shows that if wind speeds are too low, the blades cannot rotate and therefore do not generate energy. This is called the cut-in speed and happens around 3 M/S. From this point, the marginal power output increases with marginal wind speeds until a saturation point is reached. This is called the rated speed and happens around 12 M/S in the above example. Lastly, the turbines will stop rotating if the wind-speed reaches a certain speed due to the risk of damaging the turbine. This is called the cut-out speed (Albadi M. , 2009). All turbines have unique power curves and to optimize production, it is essential that the chosen turbine matches the forecasted wind speeds at the project-site. This ensures that the turbine stops as rarely as possible and operates around its saturation point as much as possible. As mentioned in section 3.2.2.2.1.2, the trend in the supply chain is that suppliers are specializing their offerings, to create location specific turbines which will generate a more efficient power generation. Furthermore, there is a trend towards larger turbines, which increases the rated-speed and cut-off period thus allowing for more energy production.

3.2.1.2.2 The capacity factor

The capacity factor is a measurement of the actual production relative to what is theoretical possible for the project site (Albadi M. , 2009). As previously stated, the turbine's power curve is described by three parameters: the cut-in, rated and cut-out speed and the wind speeds are characterized by the probability density distribution. If the wind-speed is outside the {Cut-in speed: Cut-out Speed} interval, the windmill does not generate energy. Therefore, stable wind conditions are essential to achieve a high capacity factor. One of the central arguments for moving parks further off-shore is that the wind-speeds are more stable. Therefore, developers can with a higher certainty deploy turbines with a power curve that matches the characteristics of the wind speed at the location (Albadi M. , 2009). Furthermore, as explained in 3.2.2.3, the trend among turbine suppliers is that more different models are being developed, which makes it easier for developers to match the best turbines with the wind conditions. This is forecasted to improve capacity factors going forward (Boccard, 2009). The capacity factor is often computed over a timescale of a year, averaging out most temporal fluctuations. However, it can be also computed for a month to gain insight into seasonal fluctuations. As stated in section 3.2.1.1, it makes sense for owners of wind parks to calculate revenue/costs on a monthly basis (hence forecast the monthly capacity factor) in relation to month-end closing of books, but in an investment case the investor is concerned about the total lifetime value that the project creates. Therefore, the capacity factor it calculated on a yearly basis. Continuing the example above, the capacity factor of the 2.3 MW is calculated by multiplying every wind speed with the respective probability of the outcome and then converting to an energy production using the power curve. This is then divided with the actual observed power production. To simplify, consider the five observations below:

Table 3-1 Example of Capacity factor Calculation

probability	wind speed	Power production	Hours/year
1%	1	0	87,6
7%	3	0	613,2
6%	9	2,8	525,6
5%	11	3,6	438
2%	15	4,25	175,2

The power production is derived from the power curve and hours/year is calculated as hours pr. Year[15] times the probability.

The capacity factor is given by:

$$Capactiy\ Factor = \frac{0\ MW * 87{,}6 + 0\ MW * 613{,}2 + 2{,}8\ MW * 525{,}6 + 3{,}6\ MW * 438 + 4{,}25\ MW * 175{,}2 + \cdots +}{Actual\ Observed\ Production}$$

"+…+" indicating that the numerator needs to be extended with every single observation. If the capacity factor is =1, then the park is always turned on and if the capacity factor is 50%, the park is producing 50% of the time etc. It is common practice to merely use the average wind speed instead of every single observation. This is a simplification that overstates the capacity factor. Therefore, the realized capacity factor is often much lower than what was forecasted (Boccard, 2009). As can be seen from the formula, the capacity factor is a historical number that is calculated looking back in time. However, investors need to forecast the expected capacity factor to estimate the expected energy production, which in turn can be used for the economical appraisal of the project (Albadi M. , 2009).

3.2.1.2.3 Energy loss factors

The capacity factor does not include energy loss factors that also have an influence on the quantity of produced electricity. The most important hereof are the intermittency effect, wake effect, cable losses and turbine efficiency loss (Colmenar-Santos Et. Al, 2014), which will be explained respectively.

3.2.1.2.3.1 The intermittency effect

The intermittency effect was touched upon in 3.2.1.1, but is also relevant to discuss in this section as it can influence the produced amount of electricity. If the electricity demand is low but the availability of wind energy is high, it can lead to a supply shock that can result in very low prices. Therefore, the wind power producers cannibalize their own selling price by increasing the electricity supply. This sometimes results in negative electricity prices when the low demand experiences a supply chock because of unexpected high electricity transfers from intermittent energy sources (Mayer, Schmid, & Weber, 2011). If the price gets low enough, it will not be economically attractive for the operator to sell electricity to the grid and the windfarm will shut down.

3.2.1.2.3.2 The wake effect

A wake effect is when the windmills negatively influences the wind quality for surrounding windmills. When a uniform incoming wind encounters a wind turbine, a linearly expanding wake

[15] Hours/year 365*24 = 8760

occurs behind the turbine. A portion of the free stream wind's speed will be reduced from its original speed. This lowers the energy output of the next windmill. The wake effect is thus related to the positioning of the windmill. Since maintenance costs are greatly reduced by locating windmills within close distance, it makes economic sense to locate them within proximity even though the energy output pr. Windmill is reduced slightly (Zhe & Kusiak, 2010).

3.2.1.2.3.3 Cables loss effect

Offshore wind farms transit their power to the mainland using high-voltage alternating currents. However, a lot of energy is lost in the cables due to the long distances that the electricity must travel. Attempts to solve the problem centers around new transmission technologies like high-voltage direct current (HVDC), which overcomes the limitations of traditional alternating current (AC) (Appendix A.1).

3.2.1.2.3.4 Turbine Efficiency Loss

According to Deloitte (2011), the deployed turbines decrease in efficiency as they are worn down. According to their study, the efficiency loss is approximately 0,5% yearly, which was confirmed to be a fair guestimate in our interview with Ørsted (Appendix A.1).

3.2.1.3 How annual production is calculated

Continuing on the example above, the annual production would be calculated by combining the probability density distribution of the wind speeds and the power curve of the turbines. The figure below shows an expected distribution of wind speeds with an average of 9 M/S and a power curve for a 2.3 MW Turbine. Assuming the investor uses the average wind speed to calculate the annual energy production, the investor can expect a power production of approximately 2.8 MW/hour (read from table below=. This can be converted to yearly production:

$$2.8(MW)\ * 24_{hours} * 365_{days} = 24.528\ Power\ Production\ (MWh)$$

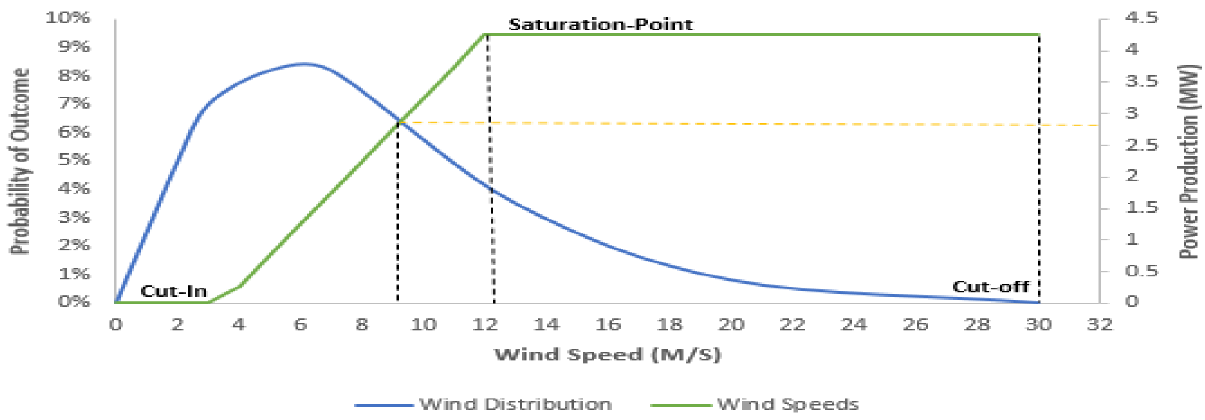


Figure 3-3 Own creation by combining figure 5-1 & 5-2

In reality, the power production given by each single wind speed probability should be multiplied by the probability to arrive at the true weighted average production. The annual production would then need to be multiplied with the capacity factor and the energy loss factors to arrive at the true annual production.

As mentioned in 3.2.1.2, we use a slightly modified method to calculate the annual production of our parks. This is because we don't have the power curves and wind distributions of all the projects. We know the nameplate capacity of the windfarm as it is given in our dataset computed from the database ***The Wind Power Net***. We use the website ***The Global Wind Atlas*** to compute the wind quality and capacity factors of the windfarms. The website uses advanced mathematical modelling to calculate the wind speed and the capacity factor at the location for the three different turbine classes[16]. The website uses historical wind tests to compute the average wind speed of a 10*10-kilometer square area at the location and then calculates the expected capacity factor for the different turbine classes if they were deployed at the location.

[16] https://www.lmwindpower.com/en/stories-and-press/stories/learn-about-wind/what-is-a-wind-class 27/3 09:15

The website calculates the following capacity factors for Aflandshage:

Table 3-2 Distribution of wind turbine class and capacity factor at given wind speeds.

Source: Jake Badger, DTU Wind

Turbine Class	Used for wind speeds	Capacity Factor
Class I	Up to 8.5 m/s	46%
Class II	>8.5 m/s but below 10 m/s	52%
Class III	Above 10 m/s	56%

Since the wind speed at Aflandshage is 8,2 m/s, it would optimal to deploy a class I turbine. We assume that the developers choose the optimal turbine for the location. We believe that this is a fair assumption given the fact that capacity factor is stated as one of the most essential value drivers in the literature (Deloitte, 2011). As such, the capacity factor at Aflandshage is 46%. We now need to determine the energy loss factor for the windfarm. As stated in section 3.2.1.2.3, the most important factors to consider are the intermittency effect, wake effect and the cable. These factors are very different to compute. For example, determining the intermittency effect requires extensive meteorological forecasts of future expected wind distributions coupled with forecast of electricity demand. Furthermore, the wake effect requires in-depth knowledge of the project site regarding how the windmills are stationed in relation to each other, the direction of the wind etc. these calculations are not the scope of our paper we do not have the required information to calculate the wake effect. Therefore, we have chosen to use a flat energy loss factor of 15% as recommended by Ørsted (Appendix A.1). The shortcoming is that the energy loss factor is not correlated to the project-specific characteristics. In our interview with Ørsted, we were told that loss of energy in the cables is the biggest energy loss factors as the electricity must travel extensive distances to the power grid (Appendix A.1). Therefore, there must be a correlation between distance shore, sea depth and cable loss. Unfortunately, we have not found any data on the relationship or any other correlation factors that can tie the energy loss to the project-specific characteristics. For this reason, we believe that a flat rate recommended by one of the most prominent companies in the business is our best bid.

As such, the quantity of electricity produced is found to be:

$$Quantity\ Produced\ Energy = Nameplate\ Capacity * Capacity\ Factor * (1 - Energy\ Loss\ Factor) * Turbine\ Efficiency\ Loss^{t} * \left(365_{days} * 24_{hours}\right) = 200.000 * 46\% * (1 - 15\%) * 0{,}5\%^{1} * (365 * 24) = 24.223\ MWh$$

As it can be seen our simplified calculations are not that far off from the theoretical correct method (24.528-24223 = 305 Kwh) and it effectively allows us to calculate the production from the 449 parks in our dataset in a much faster and easier way. As stated in section 1.5.1, the method was recommended by Jake Badger head of wind resource assessment modelling at DTU who was responsible for developing the database (Appendix A.3).

3.2.1.4 Nameplate Capacity Impact on IRR

Since nameplate capacity is both a revenue and cost driver, we have chosen to combine the analysis in section 3.3.3.

3.2.1.5 Capacity factor impact on IRR

The wind resource is a factor for a positive IRR, and as the capacity factor increases IRR increases likewise, all else being equal. However, as can be seen in Figure 3-3, the relationship is not obvious, that is, some parks with high capacity factor has negative IRR. This indicates that capacity factor alone has little explanation power of IRR, which makes sense, since IRR is a function of many variables. In order to better explain IRR one need to have a full understanding of all the variables. This will be done in section 3.3.

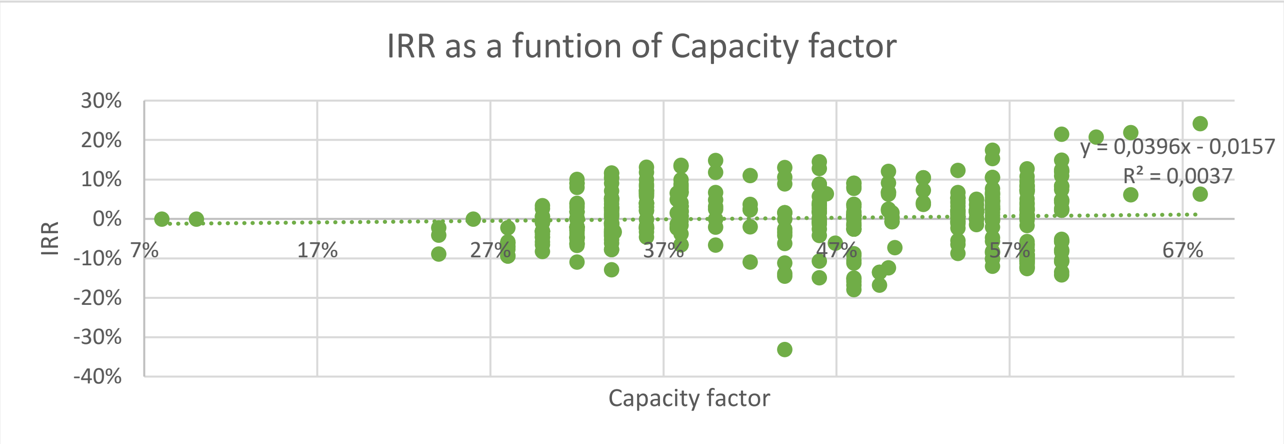


Figure 3-3 IRR and Capacity factor

Additionally, since a higher capacity factor is one of the main reasons for moving parks further from shore (recall section 3.2.1.2.2), a high capacity is also associated with a higher cost factor. This is analyzed further in section 3.3.4.

3.2.1.6 Energy Loss Factors impact on IRR

As stated in section 3.2.1.2.3, we use a flat energy loss factor of 15% for all parks as we have not been able to find any ways to tie the energy loss factor to specific characteristics of the parks. In the table below, we have tested the sensitivity of IRR to the energy loss factor, which on average goes from 3,4% to 0,2% when we include the energy loss factor. Furthermore, the IRR decreases around 3-4% for all the countries when we include the energy loss factor.

Table 3-3 IRR with and without cable loss

Country	IRR W/O Energy loss	IRR W Energy loss of 15%	Abs change
Canada	-6,5%	-9,1%	-2,7%
China	5,8%	2,7%	-3,1%
Denmark	7,3%	4,0%	-3,3%
Estonia	2,6%	-0,4%	-3,0%
France	2,8%	-0,3%	-3,1%
Germany	-7,7%	-9,8%	-2,1%
Greece	0,4%	-3,2%	-3,6%
Ireland	11,2%	7,5%	-3,7%
Japan	14,1%	10,0%	-4,1%
Netherlands	1,5%	-1,6%	-3,1%
Poland	4,0%	1,5%	-2,6%
South Korea	-2,0%	-5,7%	-3,7%
Sweden	0,5%	-2,9%	-3,4%
Taiwan	11,7%	8,3%	-3,4%
United-Kingdom	5,4%	2,5%	-2,9%
USA	-8,3%	-13,2%	-4,9%
Average	3,4%	0,2%	**-3,2%**

3.2.1.7 Revenue summary

This purpose of this chapter has been to identify what the value drivers of the revenue actually entail, how they are calculated and their influence on the investment case.

It can be concluded that the importance of forecasting electricity prices for the investor depends on the support scheme. If the project is tender offered with a PPA, the project is only exposed to market risk after the agreement expires. Therefore, the investor should only be concerned with the market prices after this point in time. Furthermore, it can be concluded that seasonality, volatility and mean-reversion are the three main components that needs to be considered when forecasting electricity prices. However, since the investment case focuses on the total project value on an aggregated level, it does not make sense to deep dive into the monthly or daily seasonality or to include the second-order mean reverting element. Therefore, these parameters are excluded from our model. Given the characteristics of the market and the time horizon of the analysis, the literature points to the Orstein-Uhlenbeck process as the most appropriate model since it takes the mean-reversion and random volatility into account. However, our calculations seems to be a bit too conservative and show too little random volatility. This entails that our forecasted prices are too stable and subsequently, the parks will achieve an overly stable cash flow in the future. This is clearly a limit to our calculations that could distort the influence that electricity prices have on the pretax- pre-subsidy IRR. Nevertheless, our analysis clearly shows that there is a positive relationship between electricity prices and IRR. This makes intuitively sense, since it is desirable for an investor to be able to sell the output at the highest possible price. In this regard, we regard the Asian markets as highly attractive as they have the highest prices by far (#1 Japan, #2 Taiwan, #3 China). The North-American markets are the least attractive and the European prices are quite equal and located in the middle-segment.

In regards to the annual expected production, it can be concluded that annual production is determined by the nameplate capacity, the wind resource at the project site, the classifications of the turbines, the capacity factor and the energy loss factors. Since there exists great geographical differences in wind quality on a global scale, this has a direct influence as to what countries are attractive investment targets. The capacity factor is often used as a proxy for the quality of the wind resource and two trends are observed in the industry that can improve the capacity factors: 1) more different turbine models are being developed by suppliers thus allowing the investors to better match the turbine model with the wind conditions at the sight. Furthermore, parks are being moved further from shore in pursuit of more stable wind conditions. We observe that the relationship between Capacity Factor and IRR is not obvious as some parks with high capacity factor has negative IRR. This is further explored in section 3.3.4. Furthermore, we save the discussion of nameplate capacity on IRR to section 3.3.3. Lastly, we observe that the influence of the energy loss factor is rather high with an average reduction in IRR of 3,2% points when the factor is included. However, we underline that our calculations use a flat energy loss factor of 15%, hence reliant on any specific sites characteristics. Therefore, the real loss factor may be lower/higher.

3.2.2 Cost

For investors, it is critical to attain a comprehensive understanding of the factors driving the costs for an offshore windfarm in order to assess the financial attractiveness of a project. This section is dedicated to describing the components of the three cost factors: CAPEX, OPEX and decommissioning costs, which in the following section will be decomposed, for an investor to fully understand. However, as we use averages from literature to arrive at CAPEX/MW and OPEX/MW (see section 1.5.1.3), we don’t actually calculate the costs ourselves. Therefore, the section will have less analytical characteristics than the section on revenue and a different structure, since we dedicate more time to reviewing the literature. CAPEX can be broken down into "Wind Turbines", "Balance of Plant", "Installation and Commissioning". OPEX can be broken down into "Operations" and "Maintenance". Decommissioning can be broken down into the individual parts of the park and windmill, e.g. turbine and foundation. Decommissioning will however be considered as one cost element, since it represents a small share of the total cost.

As such, this section is structured as following:

- Briefly outlay the historic development of offshore shore wind farms, describe how offshore energy works, and highlight which important considerations investors should make when assessing a specific projects cost
- Outlay the cost structure of offshore wind farm
- Identify key characteristics of offshore wind farms that are crucial for an investor and analyze how they affect the investment
- Discuss the prospects of offshore wind farms, looking at the past, current and future state of the industry

3.2.2.1.1 Reviewing the literature

There exists a large amount of literature on wind farm costs from 1992 to 2019 with projections all the way to 2050. Private consultancies like Boston Consulting Group, industry experts like BVG Associates, organizations like IRENA, IEA, Wind Europe and Risø Campus (DTU Wind) all have different perspectives on the costs, some more detailed than other. Likewise, there also exists a vast amount of peer reviewed articles on the matter.

Despite some discrepancies in the estimations we note that there exists a broad consensus on the general trajectory of the future offshore wind farms costs. Scholars argue that cost will decline over time while efficiency, and hence, profitability will rise (BVG, 2011; IRENA 2017). There also seem to exist a consensus that this cost reduction is caused primarily by technological innovations, supply chain improvements, and economics of scale both in "project" size (i.e. bigger nominal "name plate" capacities) and turbine sizes.

However, a trend of moving further away from shore towards deeper waters will drive costs up. The reason for going further from shore is twofold, 1) There only exists a limited area to develop wind farms on "shallow" water whereas the scalability possibilities are (almost) unlimited and 2) a better wind resource, due to stronger and more stable wind speeds as discussed in section 3.2.1.2.2. In our literature review we have also found that cost prices peaked in 2008-2010 because of high commodity prices of steel and cobber, two central cost components for producing the towers and blades (Heptonstall, Gross, Greenacre, & Cockerill, 2012). This indicates a price sensitivity towards changes in steel and cobber. Furthermore, most of the literature mentioned above focuses on the cost as one number, Levelized Cost of Energy (LCOE) which is commonly used to assess the cost efficiency of RE sources (Lazard, 2018). The aggregation of project lifetime costs is not suitable for our study as we want to assess the cost components individually. Therefore, papers focusing exclusively on LCOE cannot be used to derive the decomposed cost components. We will, however, use LCOE briefly as a benchmark against other energy sources to illustrate the competitiveness of offshore wind energy.

3.2.2.1.2 The design of a wind turbine and farm

To understand the important cost components of a wind farm and its mills, it is crucial to understand how a wind turbine works and the design of an offshore wind farm. An offshore windfarm consists of two parts, which consists of multiple parts. The two parts are: 1) Balance of Plant (BoP), 2) the Wind turbine.

The BoP consists of 1) The array cable, connecting the park to the grid and 2) the turbine foundations 3) An offshore substation, where the power is transformed to high voltage power, to reduce energy loss 4) An onshore station, which transforms power to the grid voltage, e.g. 400kV (BVG, 2011).

The wind turbines consist of multiple parts and therefore only the three main components will be explained. In short, a wind turbine converts kinetic energy from the wind into electric energy (BVG, 2011). A wind turbine consists 1) A nacelle, which converts the rotational energy from the rotors into electrical energy 2) Rotors, which creates rotational energy by extracting kinetic energy from the wind using its blades .3) the tower, which is the steel structure that the nacelle and rotors are placed on top of (NREL, 2010). The price of the turbine is relatively fixed, i.e.. , not significantly affected by the park location.

A characteristic for offshore windfarms is their scalability possibilities, especially when comparing to onshore wind farms. For onshore windfarms there exists several hindrances for establishing large parks such as local resistance (the “not in my backyard” movement) and limited amount of space (Feldman & Turner, 2010). For offshore windfarms, there exists an abundance of potential space to build on and the only limitations to do so are government restrictions. This scalability allows offshore parks to better harvest the benefits of “economies of scale.” Furthermore, if the projects turn out to be attractive, there is the possibility of “add-on” at a lower USD/kW since the fixed cost will be split amongst more capacity. In the graph below, we show the development in the average turbine size, hub height and turbine count for the projects in our dataset:

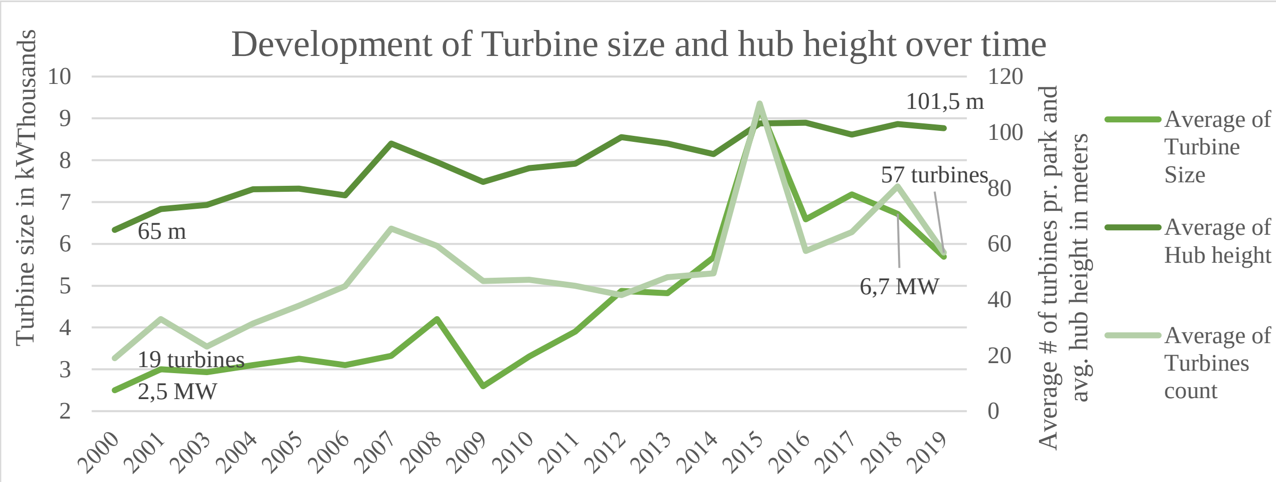


Figure 3-4 Visualization of Economies of scale

(the marginal perspective, i.e.. pr. turbine), based on own data.

As we can see, the turbines have increased in size and increased in share numbers. This shows a trend towards bigger parks in our dataset. This will, all else being equal, result in a lower unit cost.

Albeit not a part of the actual design of the wind farms, the installation and commissioning are two important and heavy cost elements of developing an offshore wind farm. We have grouped this cost into the "CAPEX" cost group, as is represents an investment in physical assets. Because of the industry's relatively young age, the literature and data with detailed decomposed cost structure for projects doesn't exists in abundance, so we've used single projects as proxy for a general cost at the time. The amount of data has however inclined over time and maturity of the industry and today sources with different costs ranges are available (Heptonstall, Gross, Greenacre, & Cockerill, 2012). This allows us to test and clarify the costs through triangulating.

To put the cost structure of offshore wind energy into perspectives, we have compared it with the other energy sources of energy, both renewable (Solar) and conventional (Coal and gas). As can be seen, offshore wind energy and renewable energy sources have a very high CAPEX/OPEX ratio.

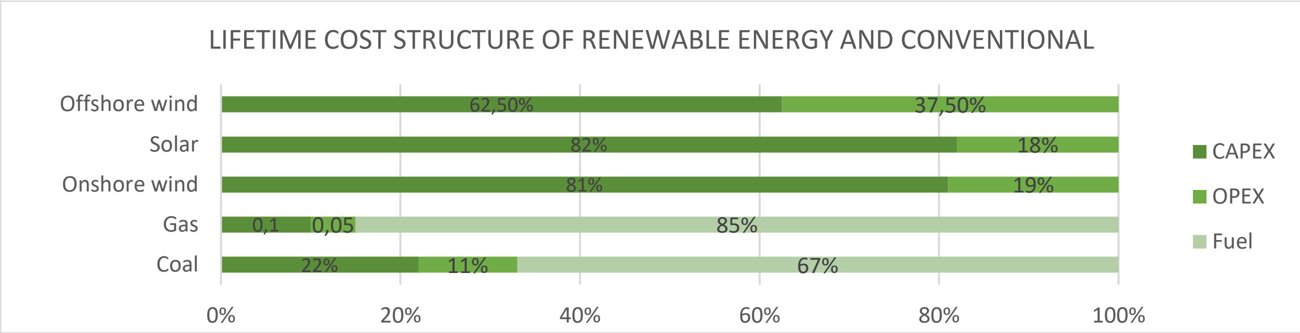


Figure 3-5 Own creation, Citi Research (Parkinson, 2015)

With this short introduction, we will now first analyze CAPEX and OPEX and then decompose the two.

3.2.2.2 CAPEX

Windfarms are capital extensive projects and approximately 80% of the total lifetime costs occur in the first 4 years of the project lifecycle, namely as CAPEX. This is largely due to the costs of turbines, which is the single largest cost component by far. Purchase of turbines also include the towers, delivery and installation (IRENA, 2017). The range of the share of wind turbines in total installed costs has historically varied from 30-50% for offshore wind (IRENA 2017; EWEA, 2013). The prices have fluctuated greatly since the offshore industry's birth at Vindeby in 1992, however, with the relative share of each cost components being relatively stable over time.

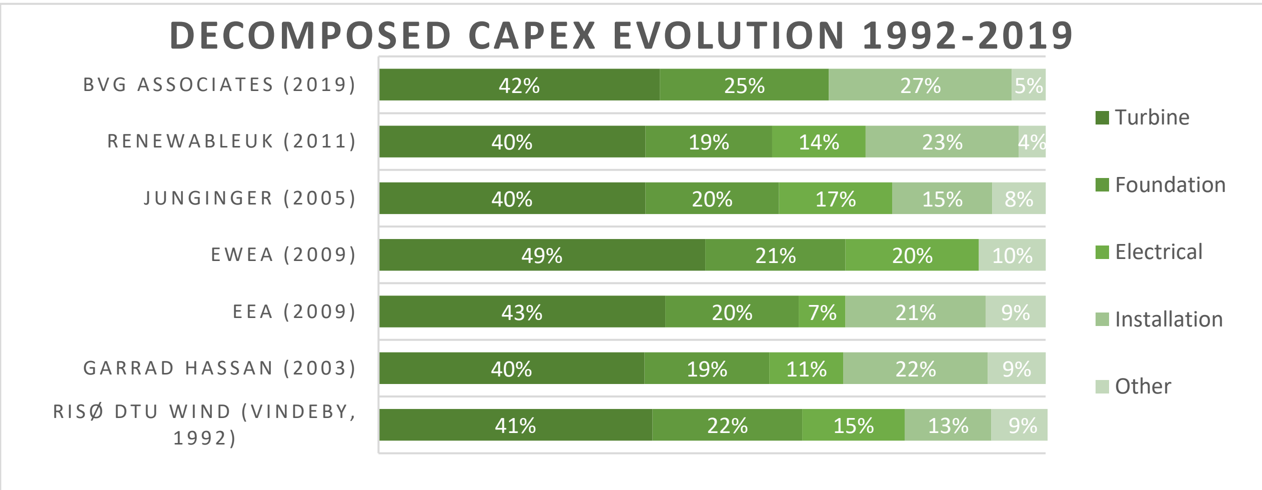


Figure 3-6 Decomposed Capex

Own creation with data from BVG Associates 2019; Prässler and Schaechtele 2012; Hepstonstall 2017.

As can be seen below, the average cost is 2.300 USD/kW as per BVG Associates (2019). These fluctuations can be explained by several trends. Firstly, a threefold price increase in copper and steel prices from around year 2005 to the peak in 2009 due to the large amount of steel and copper used in the turbines, foundation and electrical arrays (up to 12% of the total costs (Greenacre and Hepstonstall, 2012). Secondly, a trend of moving further offshore in pursuit of better wind conditions drives the CAPEX up (IRENA, 2017). Against most reports, our data findings show a volatile industry, yet to be stabilized. Our findings show, that the turbine is 30-50% of CAPEX, making it an obvious cost to try to reduce for the developers i.e. a lot of the cost reductions needs to take place in the supply chain. What we currently are seeing, is that suppliers are not lowering the prices of turbines, but rather specialize their offerings, to create location specific turbines which will generate a more efficient power generation through a higher capacity factor. The three major turbine manufactures have roughly doubled their number of offerings in their portfolio since 2010, with each now offering over 20 models (IRENA, 2017). Two factors will drive CAPEX down; 1) an increase in turbine sizes, which will mean that fewer foundations per MW is needed, reducing installation costs down. 2) The average capacity size of the park is expected to increase, driving the USD/MW down, since the fixed costs (such as installation) will be split on more MW (IAE 2017). The graph below is based on 89 CAPEX USD/kW observations in the literature through time. We use the average cost for the respective years, to account for outliers. Prices has been inflation adjusted.

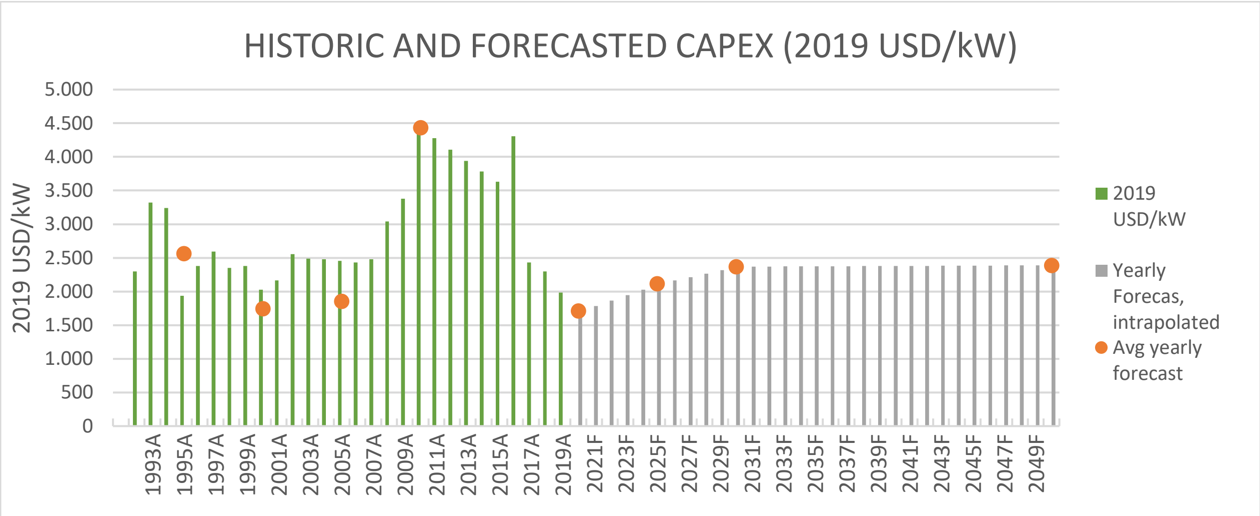


Figure 3-7 CAPEX development through time.

Triangulated data based on BVG Associates (2019), BVG Associates (2017), BVG Associates (2012), BVG Associates (2011), DEA (2018), Prässler and Schaechtele (2012), IEA (2017), Greenacre and Hepstonstall (2012). Costs adjusted for inflation and converted to 2019 USD/kW. (n=34). See Figure 8-1 for actuals (not avg.) plot with n=89).

As can be seen below, the relative share of costs groups is very similar, indicating that there exist limited national differences. Again, it is seen that turbines, foundation and installation are the key elements, representing 85-90% of CAPEX.

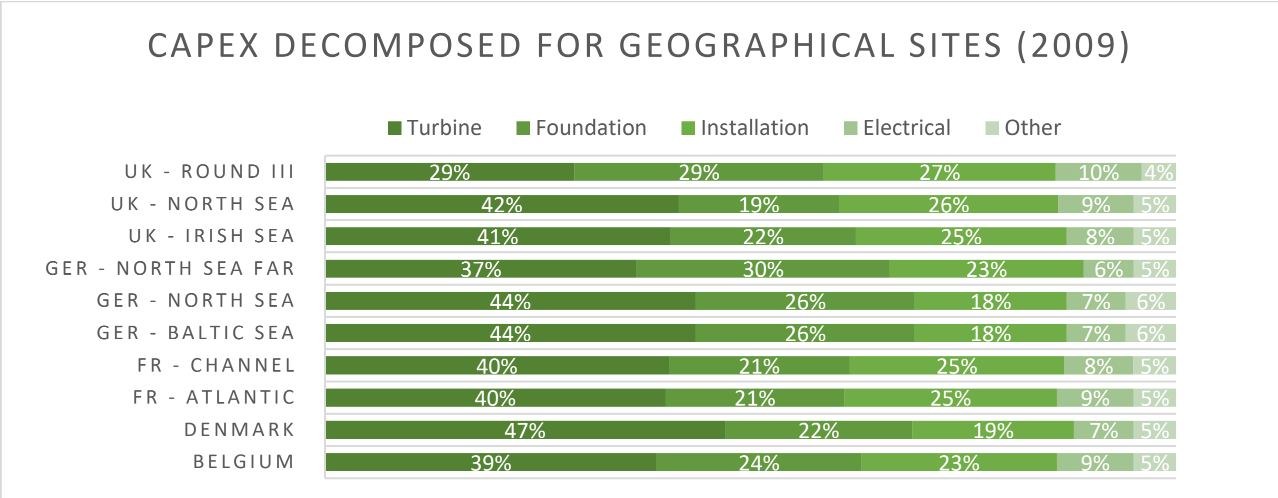


Figure 3-8 CAPEX Decomposed (Prässler and Schaechtele, 2009)

However, we have found that CAPEX is variable to the location of the farm, i.e. the depth and distance to shore, with the balance of systems and installation primarily being affected. Madariaga et al (2012) cites EWEA (now Wind Europe) for the below relation between cost and distance to shore and depth:

Table 3-4 CAPEX factor as function of distance to shore and sea depth, source Madariaga et al (2011)

Depth	Distance from shore (km)							
(m)	>0	>10	>20	>30	>40	>50	>100	>200
10-20	1	1.02	1.04	1.07	1.09	1.18	1.41	1.60
20-30	1.07	1.09	1.11	1.14	1.16	1.26	1.50	1.71
30-40	1.24	1.26	1.29	1.32	1.34	1.46	1.74	1.98
40-50	1.40	1.43	1.46	1.49	1.52	1.65	1.97	2.23

We use this factor to account for the increasing cost/kW by multiplying CAPEX/USD with the Capex Factor for the given location.

3.2.2.2.1 Cost components

We will now decompose the 3 major cost elements for CAPEX namely, balance of plants, wind turbines and installation.

3.2.2.2.1.1 Balance of plant components

This cost group consists of everything necessary to generate power and connect the power output to the grid but the actual wind turbines. It represents between 30-50% of the total CAPEX. Below a split of the major parts of BoP. Today the costs for BoP are 1.570 USD/kW.

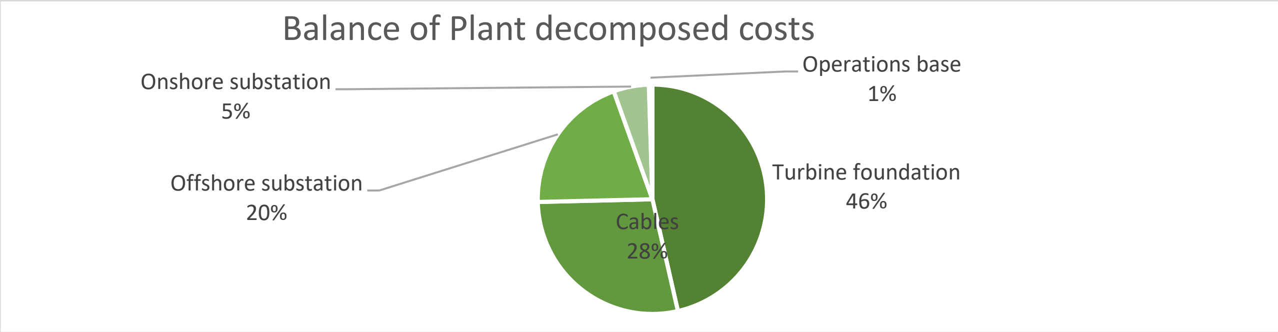


Figure 3-9 Balance of Plant decomposed costs (BVG Associates, 2019)

This cost group is very sensitive to the location of the wind farm; the further away from shore and the deeper seas the costlier it will be (Madariaga et al, 2012). As subsequently shown in section 3.2, we observe a trend in our data of parks moving further offshore, which subsequently matches the literature (IRENA, 2017). This has increased the BoP costs especially due to the higher costs of grid connection. Furthermore, parks are likely to continue to move further from shore in the future, thus increasing the BoP (and subsequently CAPEX) even more (Wind Europe, 2017).

The major cost component in BOP is the turbine foundation which accounts for 46% of the costs. The other major BoP cost component is deployment of cables also known as the grid connection. This costs accounts for approximately 28% of BoP costs (Krohn, Morthorst, & Awerbuch, 2009). It should be noted that grid connection in some countries gets paid by the government as part of the support schemes. As will be shown in section 4, this is the case for countries such as Denmark, The Netherlands and Germany. This has a major influence as to who bears the costs and subsequently the risk.

3.2.2.2.1.2 Wind turbines

Wind turbines are the single biggest costs of CAPEX and account for 40-50% of the total CAPEX. Today they cost approx. 1300 USD/kW (BVG, 2011). As can be seen, Nacelle, rotor and blades consists of approx. 70% of the turbine costs. These parts are crucial for generating electricity. According to the literature, a current trend among turbine manufactures is development of more different turbine models with different power curves thus allowing investors to better match the wind turbines with the wind conditions at the selected location (IRENA, 2017). This allows for higher capacity factors and a higher annual energy production. However, from a cost perspective Enevoldsen and Xydis (2019) points that blades longer than 60m require more carbon fibers thus increasing cost faster than potential energy gain. As such, they indicate that there is a break-even point where increasing the size of the park does not generate value as the gains are capitalized by the extra costs of the turbines. Since offshore farms can generate a higher output with smaller turbines, they can benefit more from economies of scale than onshore parks. This is an observation opposing the general trend in IRENA (2017) and important for investors to understand, as shorter blades costs less and provides the same efficacy and hence capacity factor.

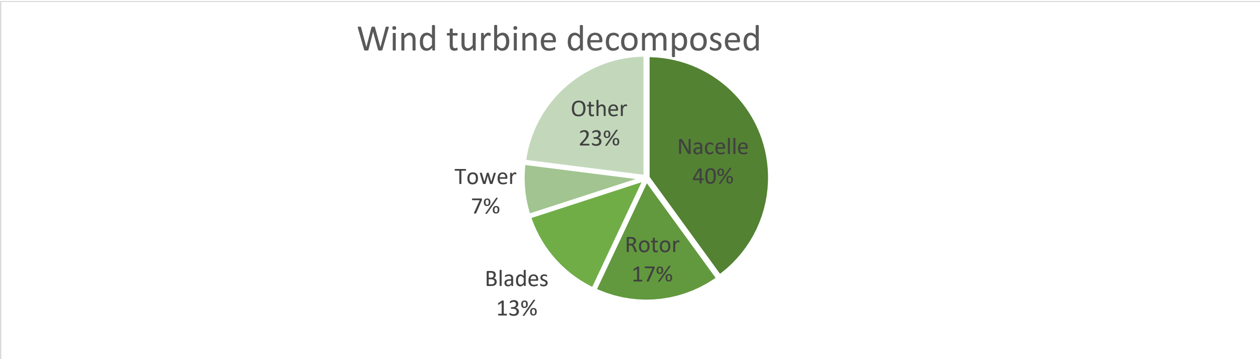


Figure 3-10 Wind Turbine decomposed costs (BVG Associates, 2019)

3.2.2.2.1.3 Installation and commissioning

Below, a decomposed cost structure of installation and commissioning is presented.

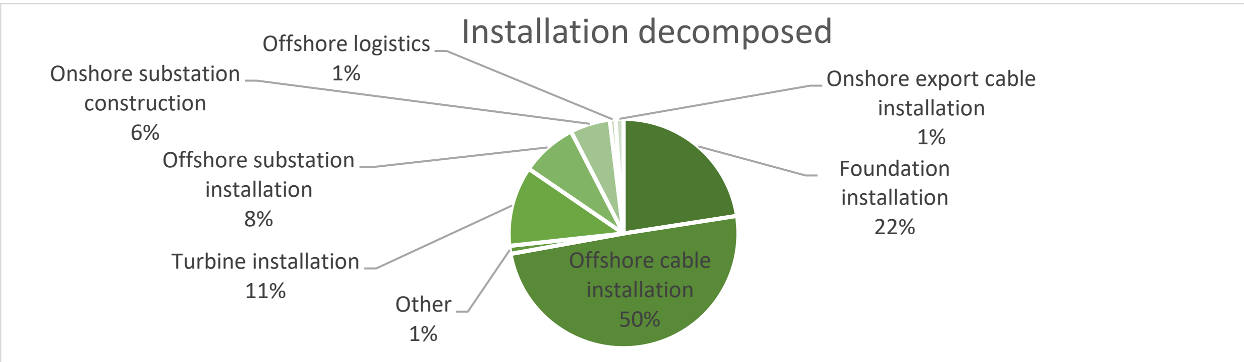


Figure 3-11 Balance of Plant decomposed costs (BVG Associates, 2019)

The current cost of this is 850 USD/kW and account for 27% of CAPEX (BVG Associates, 2019). As can be seen it is a group consisting of many parts, why the timing and planning of this post is crucial, as delays are costly (Myhr et al., 2014). The major single costs groups are foundation and offshore cable installation, accounting for combined approximately 50%. This cost is also very sensitive to location, i.e..distance from shore and depth as Madariaga et al (2011) shows. According to Greenacre and Hepstonstall (2012) that installation cost can increase as much as 25% for a 15m depth increase.

3.2.2.2.2 How CAPEX is calculated

In section 3.3.2 it was stated that our cost parameters are derived from literature comparisons on a USD/MW basis. We collect data from reports and peer-review articles and use averages to arrive at the data points for our valuations. We calculate the CAPEX cost for the specific project by multiplying the cost/MW with the nameplate capacity (and the CAPEX factor. Therefore, the development in CAPEX can be broken down to three parameters:

1. The data points derived from the literature comparisons (Unlevered CAPEX/MW)
2. The capacity of the park
3. The CAPEX factor

For the project Aflandshage the calculation of CAPEX is as follows.

First we determine the project start year, to determine USD/kW which in 2017 is 2.433 USD/kW (see appendix, Figure 1-1). We then determine the location depth and distance to shore which is 7 meters and 3 km, which gives us a CAPEX factor of 1,02 (see Table 3-4).The site specific CAPEX/MW is then: 2481,52 USD/kW. To calculate the total CAPEX we simply multiply the CAPEX/MW with the Capacity of the project:

$$2481{,}52 * 200MW = 496\text{m USD}$$

This is then split on 4 years with the distributions stated in section 2.3 : year 1: 6%, Year 2: 10%, Year 3: 34% and Year 4: 50%.
This prices correlates to a cost of 19,84m USD per wind turbine fully installed (assuming 8MW Turbines)

3.2.2.2.3 CAPEX impact on IRR

As can be seen below, IRR naturally has a negative relationship with CAPEX. As CAPEX/MW grows, IRR falls. This is intuitively expected, and as we will later visualize, projects built in a period of high CAPEX/MW and with a high CAPEX factor will give lower results. However, as in section 3.2.1.4, CAPEX/MW on its own has little explanation power of IRR. This again argues for combining the learnings as we will do in section 3.3.

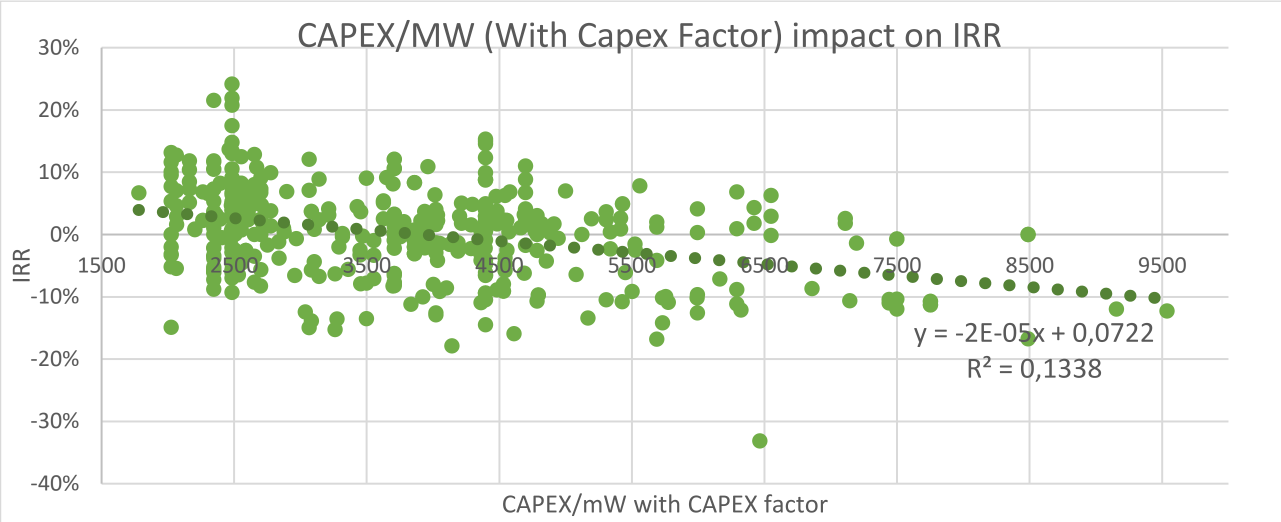


Figure 3-12 CAPEX/MW impact on IRR

As we can see from Figure 3-7, our literature review shows that CAPEX increased slightly from 2000-2006, where after we see a significant price increase from 2007-2010. This is due to excessively high copper and steel prices which gave rise to high CAPEX cost. Hereafter, we see a decreasing trend (except for 2016) until 2020 where after the literature predicts that prices will increase slightly. In the graph below, we show the development in the two factors that drive CAPEX costs; the CAPEX factor and the size of the parks. On the Y-axis we show the CAPEX factor and the size of the bubbles indicates the size of the projects (nameplate capacity).

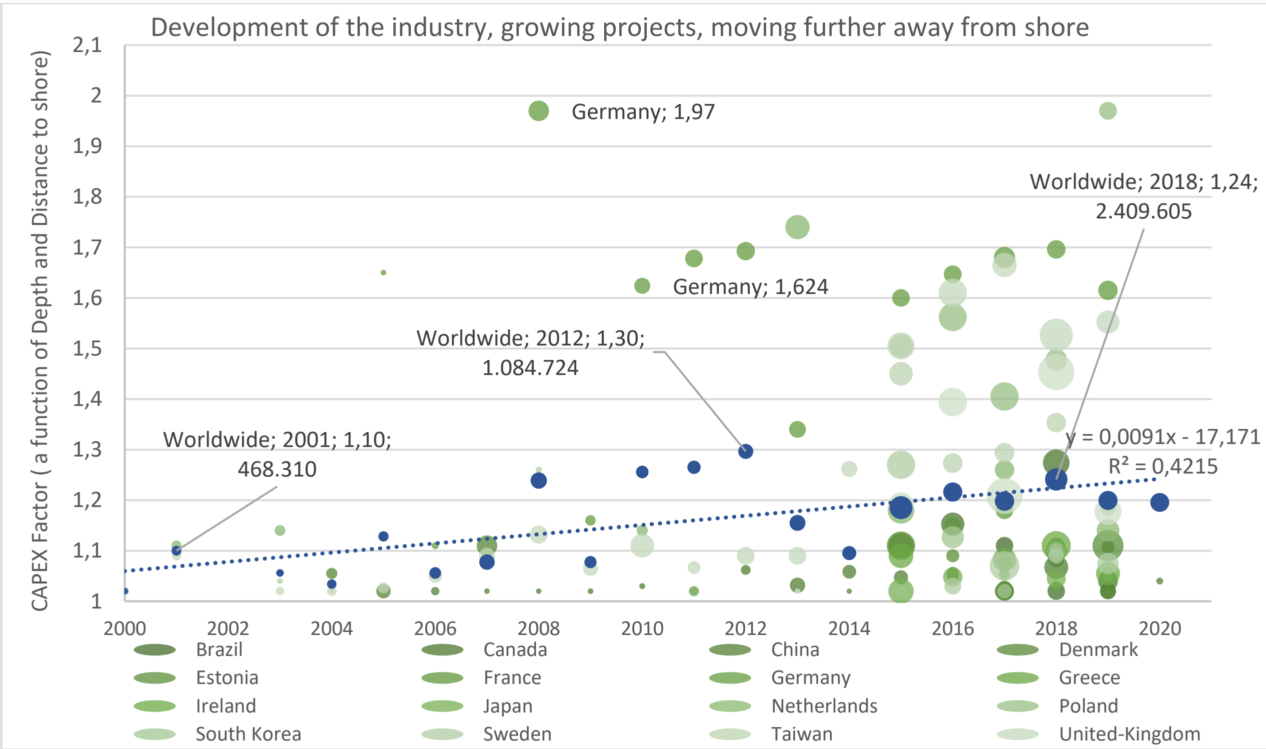


Figure 3-13 CAPEX Factor and Project size development since 2000

As such, we observe a trend of parks being developed in deeper seas, further away from shore, resulting in an increasing CAPEX factor. However, we also see greater dispersion in both the CAPEX factor and project size over time. This can be explained by the fact that new countries are entering the market and they are deploying smaller projects closer to shore. This indicates that there is an industry learning curve and our focus countries seem to be at different stages of it. Countries start with small projects close to shore and then gradually increases the project size and the distance to shore.

As such, we can conclude that:

1. On average, CAPEX/mW increases from 2000-2010, falls from 2010-2020 and then increases slightly again
2. On average, the capacity of the parks increases over time
3. On average, the CAPEX factor increases over time
4. On average, greater dispersion in the CAPEX factor and the project size over time (new market entrants)

3.2.2.3 OPEX

3.2.2.3.1 Cost components

As can be seen OPEX has risen steadily with a CAGR of 4,9% since 1992 to today's cost of 95 USD/kW (BVG, 2011). This can be explained by two main drivers. The first being a premature offshore supply-chain, i.e..a lack of adequate offshore machines to operations and maintenance jobs (O&M). This has led to higher levels of breakdowns and repairs which in turn has led to a lower load factor. Examples of typical parts with breakdowns are: "gearbox failure (especially bearings); generator failures; subsea cable damage; and operator access limitations" (Heptonstall G. S., 2017). The second driver is caused by the trend of moving further away from shore. Other drivers are more preventative (but costlier) O&M strategies, increasing labor and logistics costs and generally underestimated O&M budgets (Heptonstall G. S., 2017).

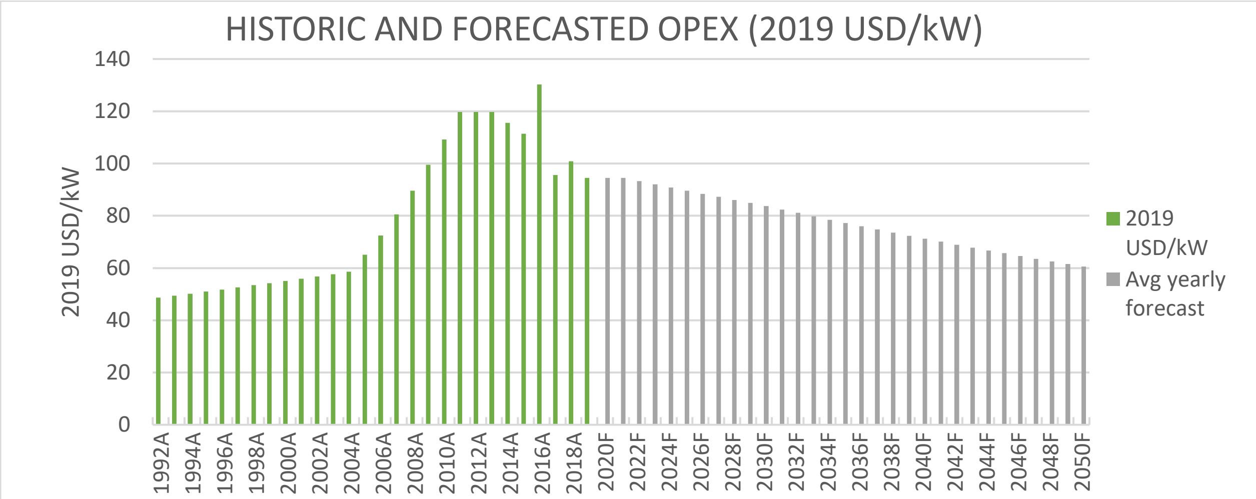


Figure 3-14 OPEX development through time.

Triangulated data based on BVG Associates (2019, 2017, 2012, 2011), DEA (2018), IEA (2017), Greenacre and Hepstonstall (2012). Costs adjusted for inflation and converted to 2019 USD/kW. (n=17). See Figure 8-2Figure 8-1 CAPEX development through time.

Triangulated data based on BVG Associates (2019), BVG Associates (2017), BVG Associates (2012), BVG Associates (2011), DEA (2018), Prässler and Schaechtele (2012), IEA (2017), Greenacre and Hepstonstall (2012), Andersen and Fuglsang (1996). Costs adjusted for inflation and converted to 2019 USD/kW. (n=80). for actuals (not avg.) plot with n=37).

There exist geographical differences in OPEX, but very limited amount of data, and only for onshore OPEX, which is a completely different cost, as OPEX for offshore is much higher and complex. Current indications are between 109 USD/kW to 140 USD/kW for offshore in Europe. Onshore ranges from 41 USD/kW in Finland to 76 USD/kW in Japan. This indicates 3,4x price difference between off and onshore, within EU. IRENA (2017) does however highlight the data inconsistency as an issue for comparison and remark that the costs could be even lower in countries like China and India. As stated in (NREL, 2017) a general lack of publicly available data exists and hence suggest "collecting" OPEX as one item. An example of the lack of detailed data is IEA whom, as many organizations doesn't offer data on a decomposed level. However, BVG Associates offers a decomposed OPEX. As it illustrates OPEX only has 2 parts, "Operations" and "maintenance and service". Through our search in literature we have only found little evidence on costs of rent, where (NREL, 2017) indicates this to be around 8,1 USD/kW/year. And as such they recommend grouping it into OPEX. Another small cost group is insurance, which is also added to a "total" OPEX. OPEX account for between 20-40% of life time costs for an offshore wind farm (see Figure 3-5).

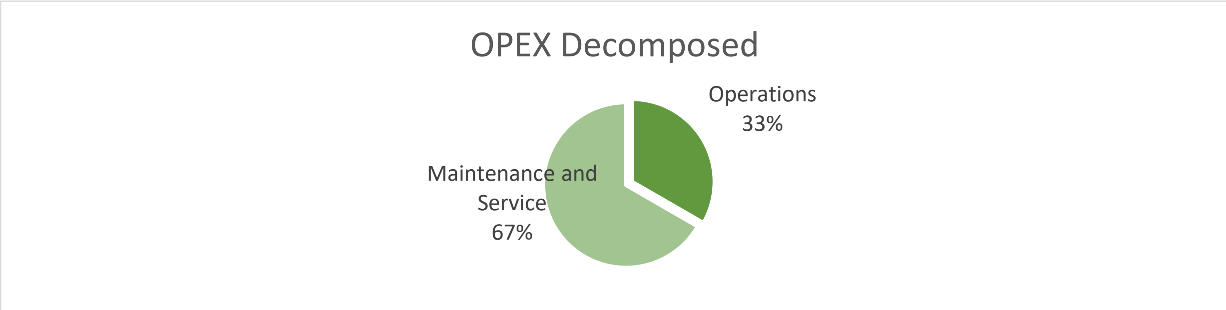


Figure 3-15 Decomposed OPEX (BVG Associates, 2019)

Operations is the "daily" management of the parks. This involves staff monitoring the park's performance 24/7. Daily management considers the electricity demand and shuts down the parks if electricity prices becomes unattractive. Furthermore, they administrate the maintenance and service of the park (Deloitte, 2015). The main cost driver of maintenance and services is the fact that staff has to sail to the project site in order to work on the parks. This requires specialized vessels that are rather expensive. Furthermore, due to the general harsher conditions on the ocean, offshore windfarms are exposed to harsher conditions that onshore parks (Deloitte, 2015). Therefore, there is considerable focus in the industry on optimizing maintenance and service activities to reduce OPEX whilst also achieving less downtimes.

3.2.2.3.2 How OPEX is calculated

To calculate OPEX we simply find OPEX/kW for the year and multiply it with the capacity of the project. This is done for all 25 operational years. For Aflandshage the calculation in the first year of operations, 2021 is: $94{,}5 * 200.000 = 19m\ USD$.

3.2.2.3.3 OPEX impact on IRR

As can be seen in Figure 3-14, OPEX gradually increases in the initial years of our study until 2014. As previously stated, the literature indicates that this is due to a lack of sufficient supply chains during the startup-years and because of the trend of moving parks further from shore. A lack of supply chain allows the suppliers to exploit market deficiencies and charge higher prices (Porter, 1979) whereas going further offshore makes maintenance more difficult, which makes up 67% of OPEX. Afterwards the supply-chain develops, and the industry experiences a learning curve causing OPEX to decrease in a constant state after 2014. As such, projects initiated in the early years will generally have a higher OPEX costs than those initiated in the later years (relative to size).

The plot below visualizes how a higher OPEX cost returns a lower IRR. However, like the other value drivers, OPEX has little explanatory power alone, which again argues for combining the learnings of the key drivers as we will do in section 3.3.

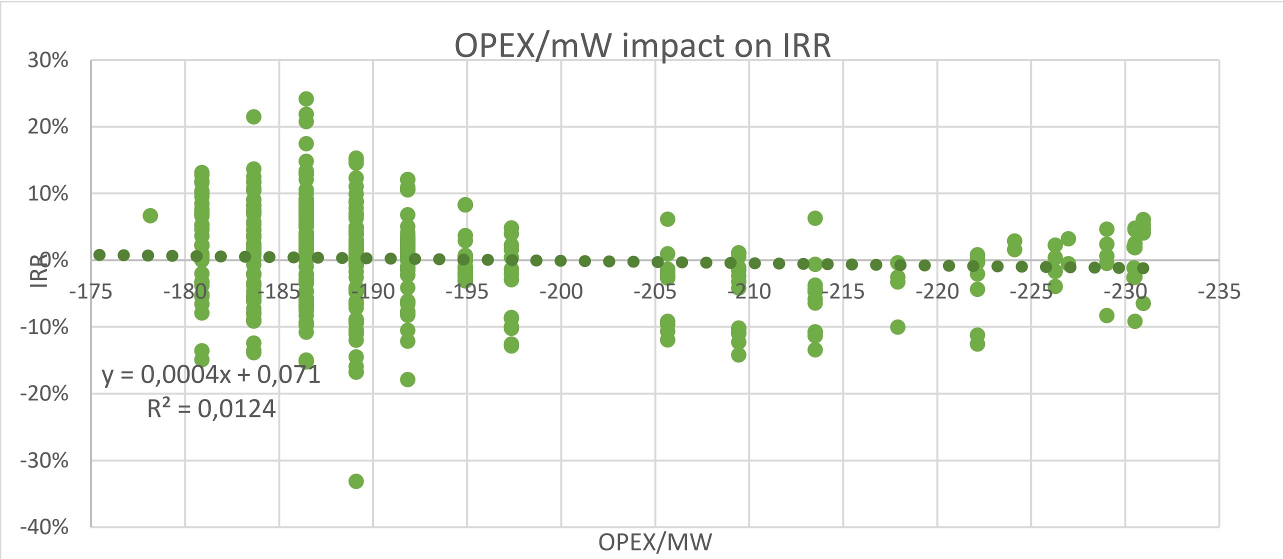


Figure 3-16 OPEX/mW and IRR

3.2.2.4 Tax

Tax is not included in our modified IRR model. The reason for this is twofold; firstly, taxes are country and project specific making it impossible to include in the model. Secondly taxes are in some countries used to create incentives, i.e.. they are in fact part of the subsidy schemes. This is again specific from project to project and the impact for an investor will be analyzed in chapter 4.

3.2.2.5 Decommissioning costs

Our decommissioning costs is assumed to be a fixed function of size during the entire period 208,8 $/MW. This choice follows a comprehensive study conducted by BVG (2011). Since the decommissioning costs is flat and since it constitute an insignificant amount of the total costs (4,5% on average), it does not have a significant influence on the financial attractiveness of the projects. For this reason, we have chosen not to go further in-depth with describing the cost factor. But the decommissioning cost is included in the calculations.

3.2.2.6 Offshore wind energy's current competitiveness

Throughout this chapter we have deliberately ignored the popular metric Levelized Cost of Energy (LCOE). LCOE has its limitations for an investor wanting to perform a thorough cost analysis because of is aggregation of costs. However, it does serve perfect as a benchmark metric (IRENA, 2017). The

LCOE measurement takes all costs and revenues generated by the technology into account as well as the time value of money.

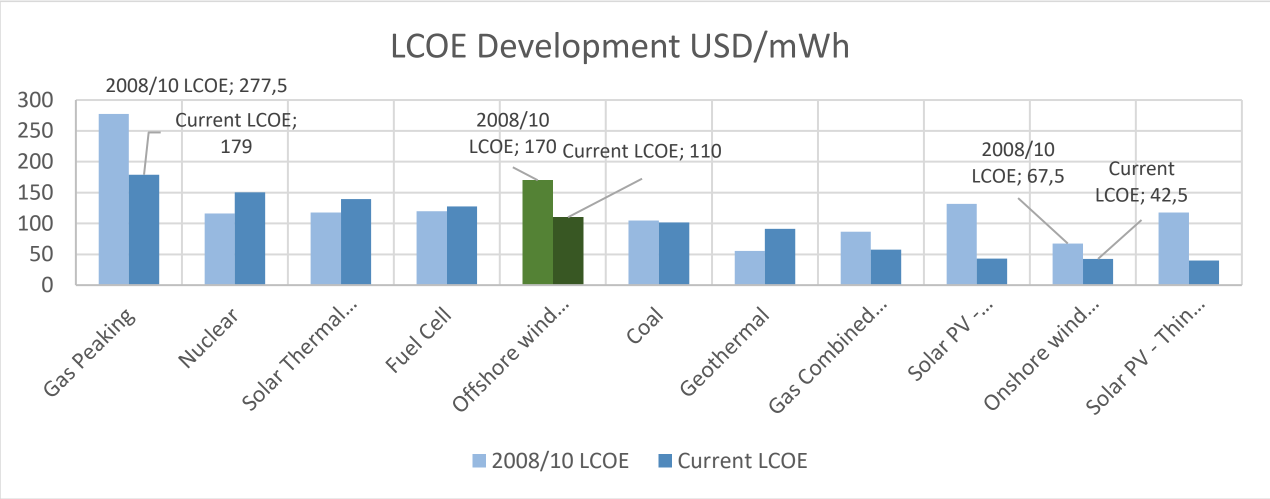


Figure 3-17 Own creation with data from IRENA (2017), Lazard (2018, 2008), IEA (2018)

Since distinct ways of generating electricity incur significantly different costs at different points in time, the Levelized Cost of Energy (LCOE) measurement is commonly used to compare the economic feasibility of different energy sources

The measurement is given by the following formula:

$$LCOE = \frac{Sum\ of\ Costs\ over\ Lifetime}{Sum\ of\ Electrical\ Energy\ Produced\ over\ Lifetime} = \frac{\sum_1^N \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_1^N \frac{E_t}{(1+r)^t}} \qquad (4.2)$$

Equation 3-1 IRENA (2017)

Where: $\mathbf{I_T}$ = Investment expenditures in the year t, $\mathbf{M_T}$ = Operations and maintenance expenditures in the year t, $\mathbf{F_T}$ = Fuel expenditures in the year t, $\mathbf{E_T}$ = Electrical Energy Generated in the year t, **R** = Discount rate and **N** = expected lifetime.

As can be seen LCOE for offshore wind energy has fallen 35%. This is, compared to other sources, is not too impressive, Solar energy shows a 66% decrease. The explanation for this relatively small improvement can be found, as explained earlier, in the trend of moving further offshore thus increasing the costs. This increase is offset by improvements in energy efficiency and financing cost, e.g. This indicates a possibility for investors, as more investors and investments into offshore wind energy, will lead to a decrease in LCOE, all else being equal. However, LCOE's disadvantage is also visible; it is not possible to see which improvements have contributed to the current state. Also, the "global" figure leaves the reader with much uncertainties, as there exits many geographical differences, something we will highlight later in our analysis.

3.2.2.7 Cost summary

As found in our literature review, the costs of the projects are a key driver, especially CAPEX (see Figure 3-5). We find in our analysis, that projections of the costs generally have been too optimistic, something for investors to keep in mind, when assessing cost projections. However, we see a general decreasing trend in costs due to technological innovations, supply chain improvements and a general learning curve, which is incorporated in our cost projections of CAPEX and OPEX shown in Figure 8-1 and Figure 8-2. In addition, we find that CAPEX is sensitive towards commodity prices and to moving further from shore due to the CAPEX factor. Our analysis shows fluctuations in CAPEX, as the industry has explored new technologies and pursued new potential, i.e.. building bigger parks, with bigger turbines and moving further away from shore (recall Figure 3-4). The benefit of the latter, is improved wind conditions I.e. a higher capacity factor, better expansion possibilities and the possibility to make larger parks thus benefitting more from economies of scale. Our literature review indicates that there is a “maximum” size for the wind turbines, as the turbines can reach a size where the marginal costs outweighs the revenue. This saturation point is not reached as fast for offshore wind parks, thus allowing offshore parks to benefit more from economies of scale. Furthermore, the section has shown an increase in OPEX up until 2016 caused mainly by two things; an immature industry that had to build up an entire new a supply chain of e.g. O&M vessels. This initially increased costs. Second, OPEX has been impacted by the shift of moving further towards sea. A lack of supply chain has allowed the suppliers to exploit market deficiencies and charge higher prices and moving further from shore has made maintenance more difficult, which makes up 67% of OPEX. As the supply chains has developed and due to the learning curve, OPEX has decreased.

3.3 Analysis of IRR

In this section we will analyze how the IRR has developed over time (shown as average pr. country pr. Year). We will analyze how each driver affects IRR and we will deep dive on the best and worst performing countries and explain why they rank as they do. This will give the reader a thorough understanding of how the key value drivers impact IRR. As we have found in the previous sections, analyzing the value drivers against IRR one by one only explains a minor part of the trends. This argues for combining them in order to get a more comprehensive picture for investors to understand. Therefore, we conduct a multiple linear regression in order to see how the drivers affect IRR, to see what an investor should focus on when trying to get the best returns. The analysis below has been prepared based on the data from the 449 offshore wind parks.

3.3.1 IRR per country over time

Below we present a matrix showing the pretax-pre-subsidiary IRR for our 16 countries split on 20 years.

Average of IRR in %	Project start																				
Country	**2000**	**2001**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**
Canada																-11,71	-7,02	-8,68	-5,47		-9,15
China					-2,50	-0,51	-3,92	-4,37	-3,28	-3,09	-2,83	-0,61	0,69	-0,48	3,28	3,85	7,58	8,11	6,41	6,68	2,74
Denmark				4,39	2,48		-1,69							0,12	2,19	3,14	5,28	6,13	7,69		4,01
Estonia															-4,14	-1,75	0,77	0,81	0,89		-0,44
France																-2,53	-1,63	2,17	5,33		-0,33
Germany					-9,17	-8,28		-12,58	-10,03	-11,50	-11,61	-10,36	-9,59		-11,31	-10,42	-8,23	-7,50	-7,24		-9,77
Greece															-6,93	-5,62	-1,44	-2,32	2,64		-3,19
Ireland															2,58		7,68	8,21	9,01		7,53
Japan	2,85										0,53				10,64	10,61	10,12	12,64	11,40		10,02
Netherlands		-0,54	-1,17							-6,42	-10,95		-8,71		-2,28		0,48	1,41	2,27		-1,64
Poland															-0,33	0,28	2,84	3,37	0,44		1,45
South Korea													-12,88		-7,72	-7,22	-6,11	-3,99	-3,89		-5,72
Sweden			-2,58	-6,50				-11,21							-6,30	-2,44	3,51	0,03	2,68		-2,88
Taiwan															4,27	7,96	9,84	9,96			8,26
United-Kingdom	1,57	3,19	1,95	5,73	3,73	2,57	1,32	-0,33	-1,46	-0,61	0,36	-0,20	1,31	0,88	2,02	2,43	3,56	6,66	6,35		2,64
USA													-12,58		-12,95	-20,65	-9,99	-11,26	-11,22		-13,25
Average	**2,21**	**1,33**	**-1,39**	**2,75**	**0,33**	**-0,22**	**-0,74**	**-3,72**	**-4,06**	**-6,16**	**-5,62**	**-4,08**	**-4,01**	**-0,19**	**0,24**	**-0,40**	**3,01**	**1,13**	**2,47**	**6,68**	**0,22**

Figure 3-18- Pretax-Pre subsidiary IRR for focus countries split on 20 years

As it appears there are substantial differences in the IRR's between the countries and over the years, which we will subsequently analyze.

3.3.2 General industry trend

In the graph below, we see the development in IRR and project size over time. The size of the bubbles shows the size of the projects and the location of the bubbles shows the IRR.

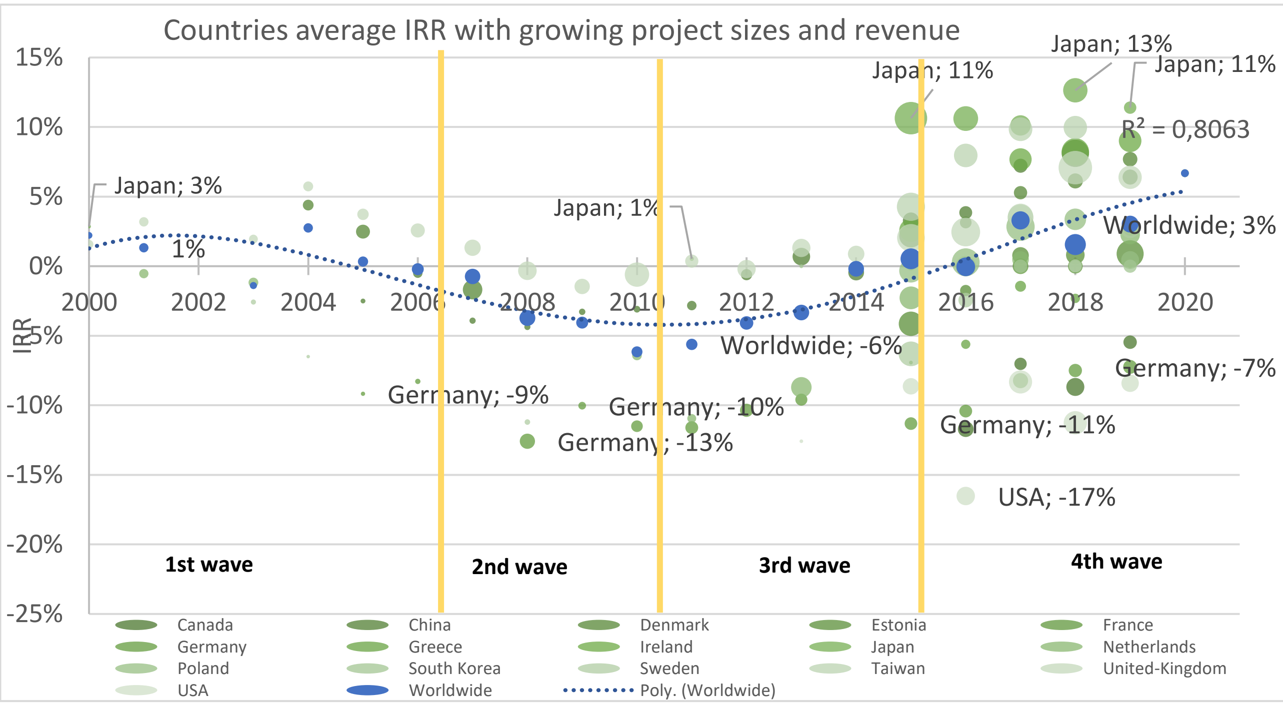


Figure 3-19 IRR and Projects revenue (bobbles size) over time

We observe that the IRR's has experienced four "waves" with different trends, because of learning curves and external factors. Generally, we see a trend of increased revenue (larger bubbles) and more scattered financial performances over time. We especially see outliers in the second and third wave.

S-curve

The development of the entire industry (within our scope of 16 countries) can be explained by the nature of the so-called s-curve theory that argues that technological development happens in "steps", which means that the performance over time will look like the letter "S" (Foster, 1986). The curve will initially show slow improvement, then accelerated, then diminishing. This has also been the case for offshore wind, as can be from the figure above. Performance in the early days of an industry is slow (1st and 2nd wave). As the industry matures and firms gain a deeper understanding of the technology, improvement begins to accelerate (3rd wave). As the technology begins to meet its inherent limit then the relative benefit of each dollar invested will have a diminishing effect, which will cause the s-curve to flatten out (4th wave). It should however be noted that the shape of an s-curve is not set in stone and neither is the limits of an industry known in advance, indicating that predictions should be made wisely if using an s-curve to predict the next levels or "waves" of the offshore wind industry (Schilling & Esmundo, 2009). Below we analyze the pretax-pre-subsidiary IRR through the 4 waves.

First wave

In the first wave from 2000-2006, we see few, small projects being developed close to shore with subsequently low CAPEX and revenue. The CAPEX factor was on average 1,07, which can be explained by the fact that developers were harvesting "the low hanging fruits" by taking the easy spots close to shore, perhaps to prove the concept before more ambitious projects were initiated.

Second wave

In the second wave from approximately 2007-2010, we see an increase in the number of initiated projects as well as improvements in both cost and revenue. This could possibly be explained by the fact that the industry gained legitimacy in the first wave where after more investors were subsequently willing to invest in the second wave. Furthermore, RE goals were established in this period (see chapter 1) for many of the countries in our dataset, which with all likelihood lead to an increase in the number of projects that were subsequently tender offered by governments. In the second wave, the capacity factor improved by 1% point, the electricity prices increased by 3% and the average park size increased with 52,8%, which combined with an increased CAPEX factor lead to a CAPEX increase of 56%. In the data set we calculate an average IRR of -4,6%, which is mainly caused by CAPEX which is excessively high in this period due to the price peaks in commodity prices for many of the input factors for turbines (see section 3.2.2.2).

Third wave

In the third wave, we see a further increase in the deployment of parks and increased revenue due to larger park sizes. However, this is the period where we see the most significant data outliers mostly stemming from projects from Germany and the Netherlands where parks are being established at abnormally high CAPEX factors, in turn resulting in low IRR's. This indicates that the modern markets are experimenting with more difficult site locations in the pursuit of higher revenues and avoidance of pressure from the public related to wind parks close to shore. These projects are shown as outliers in the graph above. Perhaps, the capacity factors have not turned out as expected, which indicates that an increased distance to shore doesn't always result in a better capacity factor. From the second to the third wave, CAPEX increases by 10% due to an increase in park sizes of 35% and an increase in the CAPEX factor of 3%. The average increase in CAPEX factor is only 3% because many new countries entered the industry, and deploy parks close to shore. This distorts the "average" calculations. The average electricity prices decrease slightly, and the IRR improves slightly due to bigger parks being deployed.

Fourth wave

The capacity deployment really takes off in the fourth period where we see a tremendous increase in the sheer number of parks coupled with significant increases in revenue due to increased park sizes. We also see a great dispersion in financial performance in this period and in general we see an increasing deviation over time. From the third to the fourth wave, we see a slight decrease in the CAPEX factor coupled with a 16% increase in capacity factors. From our literature review, we derive a high learning curve in this period, which ultimately leads to a CAPEX reduction of 21%. Ultimately, this leads to an average IRR of 0,39%.

Comparison

Below we summarize the compared key drivers discussed above.

Table 3-5 Comparison of Key factors (single items) and IRR

Factor	00-06	Periodic difference	07-10	Periodic difference	11-15	Periodic difference	16-20'
Capex factor	1,07	*9%*	1,16	*3%*	1,20	-2%	1,18
Capex/MW	2.386	*56%*	3.723	*10%*	4.109	-21%	3.237
Capacity factor	49,8%	*1%*	50,3%	*-8%*	46,4%	-7%	43,0%
Electricity price (avg)	0,056	13%	0,063	-3%	0,061	-8%	0,057
Capacity (avg)	90,9 MW	*52,8%*	190,9 MW	*35%*	297,1 MW	16%	354,1 MW
IRR	0,18%	*-2662%*	-4,60%	*-10%*	-4,13%	-110%	0,39%

3.3.3 Nameplate capacity trend

As mentioned several times both in section 3.2.1 and 3.2.2, there is a trend towards establishing bigger projects. Throughout the time period of our study, the average capacity of the farms has grown with a CAGR of 10,6%, which clearly supports this. We find it interesting to analyze whether the increase in size has improved the IRR, as it should according to the literature, due to economies of scale etc. Recall that that CAPEX and OPEX are calculated as following:

$$Opex = Nameplate\ Capacity * OPEX\ pr. MW_t$$

$$CAPEX = Nameplate\ Capacity * CAPEX\ pr. MW_t * Capacity\ Factor$$

If there were economies of scale in costs then CAPEX pr. MW and OPEX pr. MW should decrease relatively when project size increases, i.e.. include a diminishing marginal cost factor. This is not the case in our valuations. Therefore, our model does not capture economies of scale in costs per se. In a real life project, there will naturally be economies of scale, since there are fixed costs associated with building a project, but this is not incorporated in our model. However, if an increase in project size leads to a marginal higher revenue than costs then our model shows economies of scale and establishing bigger parks leads to a higher IRR and vice versa. We test this by looking at the total profit margin for the projects. Since OPEX is the only cost in the operational phase, the profit margin can be calculated as:

$$Total\ Profit\ Margin = \frac{Total\ Revenue - Total\ OPEX}{Total\ Revenue}$$

We calculate the average profit margin for projects under and above the sample mean for capacity (288MW) in four different time periods:

Avg. Profit Margin	Under 288 MW	Over 288 MW
Overall	56,8%	57,88%
From 00'-05'	56,6%	#N/A
From 05'-10'	58,0%	62,2%
From 10'-15'	57,8%	59,9%
From 15'-20	55,9%	56,7%

Figure 3-20 Difference in OPEX-Revenue as share of Revenue

As we can see from the table above, we see an improvement in the profit margin in all four time periods when the park size increases. This indicates that there are economies of scale in establishing larger parks. Since CAPEX and OPEX are linear functions of project size, they do not show diminishing marginal costs. Therefore, economies of scale is evident because an increase in nameplate capacity leads to a higher marginal revenue than costs. However, we urge investors to dwell on the size of the turbines, which we have found to have a diminishing economic attractiveness when it becomes too big, due to more technical and hence expensive materials such as carbon (see section 3.2.2.2.1.2). This could be overcome with time, but for now, the industry has its limitations, which affects the economic attractiveness.

3.3.4 CAPEX factor vs. Capacity factor

In section 3.2.1.2.2, it was argued that one of the central arguments for moving parks further from shore is that more stable wind conditions results in higher capacity factors. Therefore, we find it interesting to test whether capacity factors have improved as parks have moved further from shore.

The development is depicted in the graph below:

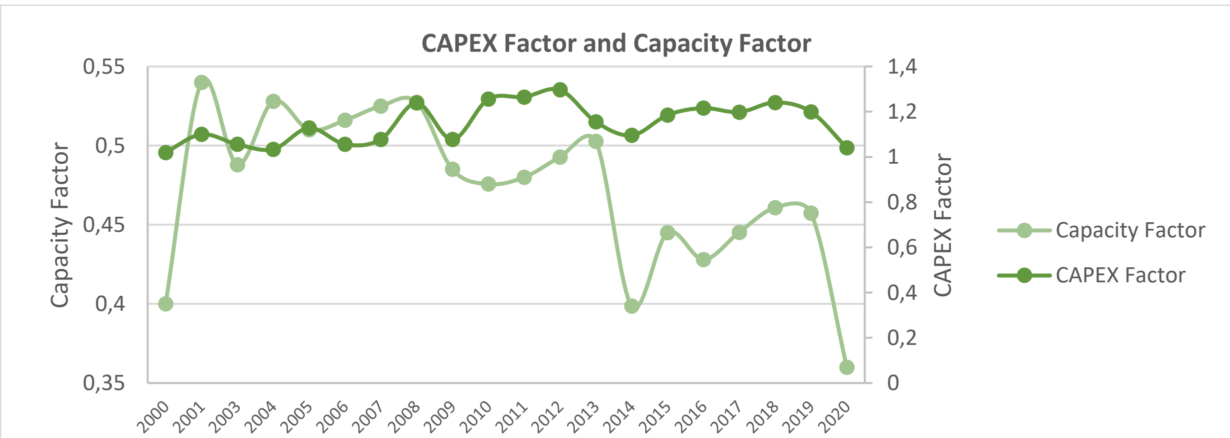


Figure 3-21-Capex Factor Vs. Capacity Factor

We would expect the development in the two factors to closely resemble each other, but this does not seem to be the case. For example, in 2009-2012 the CAPEX factor is on average high, but the Capacity factor doesn't follow accordingly. Additionally, the CAPEX factor increases from 2014-2018, but again, the Capacity factor does not improve accordingly. Therefore, moving parks further from shore has not resulted in much improvement in the Capacity Factor. When calculating the CAGR of the capacity factors, we find it to be only 1% (00' to 19'). As such, we conclude that moving parks further from shore has increased the CAPEX factor more than it has improved the Capacity factor. This shows that a higher capacity factor is not a certainty when parks are moved further offshore and we observe that moving parks further from shore has increased the cost-drivers for CAPEX more than it has improved the revenue-drivers. However, it is possible that by moving parks further from shore one can benefit from building larger parks. This is stated as one of the reasons for doing so (Deloitte, 2011).

3.3.5 The key drivers' impact on IRR analyzed through multiple linear regression

In order to test how each variable influences the project IRR we conduct a mutiple linear regression. When conducting a mutiple linear regression we assume the following (Gujarati & Porter, 2010):

1) the regression model is linear in the parameters as:

$$E(Y_t) = B_1 + B_2 * X_{t2} + B_2 * X_{3t} + u$$

Where $X_{1t}$is observation 1 (i.e. project 1) and so forth.

2) X_{1t} and X_{2t} are distributed independently of the error term u. If not, then we cannot obtain unbiased estimates of the regression coefficients.
3) The error term u has a zero mean value; $E(u_i) = 0$
4) Homoscedasticity is constant (i.e. the variance of u); $var(u_i) = \sigma^2$
5) No autocorrelation exists between the error terms u_i and u_j; $cov(u_i, u_j)\ i \neq j$
6) There must be no collinearity between the variables, X_2 and X_3, i.e. no exact linear relationship between two explanatory variables.

In order to sort our data according to country and year, we add these as dummy variables. To see the output of the regression analysis go to Table 8-1. In table 8-3 to 8-6, we test the linearity assumption. In

Figure 8-4, we show a scatter plot of the residuals vs. the fitted values (estimated responses). As we see, the red line is stabel, relatively flat and there is no pattern in the data points, i.e. the linearity assumption holds (Gujarati & Porter, 2010). Likewise the data is normal distributed, except for a few outliers, which can be seen from Figure 8-3. In Figure 8-5, we show a QQ-plot if the relationship between IRR and the variables. We see that the data plots quite well on the diagonal lines, with some outliers in the tails. This matches the findings in Figure 8-3. However, it can be argued that 95% of the observations are within the confidence interval. Lastly, in Figure 8-6 we show the standardized residuals vs. fitted values. Since, we see no trend in the data, we can deduct that the data is normally distributed.

In general, Gujarati & Porter (2010) highligts 5 attributes of a good model.

Table 3-6 5 attributes of a good model (Gujarati & Porter (2010))

Attribute	Explanation	Our model's fit?
1) Parsimony	A model should be as simple as possible.	Check – we have no excessive variables with clear relation to IRR.
2) Identifiability	Parameters must have unique values.	Check
3)Goodness-of-Fit	The R^2should be as high as possible.	A R^2 of 87,85% is an acceptable fit
4)Theoretical Consistency	The model should have consistency with theory. E.g. if supply rises, then prices should fall.	Check – If OPEX increases then IRR decreases.
5)Predictive Power	A model's coefficients should be understandable in relation to the "real world"	Check – same as above

3.3.5.1 Interpretation of the results

For the output of the mutiple linear regression we refer toTable 8-1 in appendix. We get an R^2 value of 87,85% which indicates that our model can explain 87,85% of the variation in IRR. However, it should be remarked that IRR is calculated as a functon of the net cash flows, i.e.. is dependent on the values we have in the model. Therefore a high R^2 is expected and self-explanatory. Nevertheless, the variables coefficients shows, with statistical significance, how each coefficient impacts IRR which is useful information for an investor. The variables in the regression are: OPEX, Depth, Distance_to_Shore, Capacity, Capacity_factor, Estonia, Canada, Denmark, France, Germany, Greece, Ireland, Japan, Netherlands, Poland, South_Korea, Sweden, Taiwan, United_Kingdom and China. Notice that CAPEX is not a variable in our mutliple linear regression. This is because we have decomposed the CAPEX drivers and included these instead (nameplate capacity, depth and distance to shore). However, we would expect that CAPEX has a great impact on IRR, recall Figure 3-12. Albeit it did not have much explanation power on IRR alone it was the driver with the second highest R^2 and with the most negative coeffient (impact on IRR). Electricity prices is not part of the model, as the projects do not have one single price. We could have used an average to test the approximate impact on IRR, but this would yield a biased result. This is done in a simple scatterplot in Figure 3-2, which, albeit its simplicity (the average price) shows a the most positive impact on IRR of all the variables when tested one by one against IRR. Quantity produced is not part of the model either, since this is explained by Nameplate Capacity and Capacity factor. Neither is the energy loss factor nor decomminsionnig costs included as these are completely linear related to capacity and hence would add no explaination power to IRR.

We observe three insignificant, dummy variables at a 0,05 alpha value: “Estonia” and “Sweden”. Therefore, it can be stated that these countries cannot help explain the variation in IRR. Furthermore, as previously stated, the variable “Netherlands” has been removed due to multicolinarity.

For all other variables we can confirm, that the coefficient is different from zero (i.e.. we can reject the H0 hypothesis). As previously stated, this was expected given the fact the IRR was calculated from the variables in the model. The residual standard error gives an idea of how far observed IRR values are from the predicted IRR values. Therefore, they serve to show how accurate the model is and the closer to 0, the more accurate. However, if the value is exactly 0 this can be a sign of an overfitted model, since it indicates that the model fits the data perfectly (Gurajati & Porter, 2010). The interpretation of the intercept, is the estimated mean IRR value, when all variables are 0. This value should in the ideal world be equal to 0, indicating that the independent value is 0 when all the variables are 0. However, -2,35E+02 is considered an acceptable result, which merely indicates that the model isn’t perfect, but has some outliers in the tails, see Figure 8-4.

We analyse the project specific variables, OPEX, Depth, Distance to shore, Capacity and Capacity factor and then we will look at the dummy-variables for the different countries. Before we analyse the variables coefficients, we adjust the coefficients by multiplying them with their standard deviation. This is do to make the coefficients adjusted to scale in order to better compare them. The standard devitations are computed in Excel.

We hereby adjust for the coefficients to become somehow independent of scale.

	Coefficient	Standard Deviation	Adjusted for scale (Coefficient*Std dev)
OPEX	-5,70E-04	785,4561	-44,8%
Depth	-4,87E-04	13,5765	-0,7%
Distance_to_Shore	-2,98E-04	30,72084	-0,9%
Nameplate Capacity	1,07E-06	423228,7	45,4%
Capacity_factor	4,56E-01	0,106628	4,9%

As expected, an increase in OPEX, Depth and Distance to shore results in a reduction in IRR. We can conclude, that OPEX has enourmous effect to improve OPEX as it has a very high negative effect on IRR. Likewise, it can be seen, as we have found througout our analysis, that there exists great economies of scale with huge impact on the IRR, as the variable Capacity (i.e. the size of the park) is the most influencial driver. It can also be interpreted that a increase in depth (1m) and distance (1 km) has approximately the same impact on IRR. This further can be compared to the relative improvement of capacity factor, which shows that an increase here has more impacact on IRR than a combined increase of depth and distance. Hence, and in line with a general understanding, the wind on the location is more important than the depth and distance from shore.

Overall it can be concluded that the two main drivers are OPEX and Capacity, pulling IRR in each direction. Further, our analysis shows that finding a location with good wind conditions are just as important as moving towards deeper seas further away from shore; the two effect offsetting each other (with wind conditions being more positive, net).

3.3.5.2 General distribution of IRR

In general, the industry has experienced fluctations in IRR over time as a result of learnings, expirimental projects and different external factors such as commodity – and electricity prices. It can be seen that the latetst “wave” of project are benefitting from the industry’s learnings and with 91% of the projects being from 2010-2020, the distribution of IRR looks like . As can be seen, 51% of projects return negative IRR.

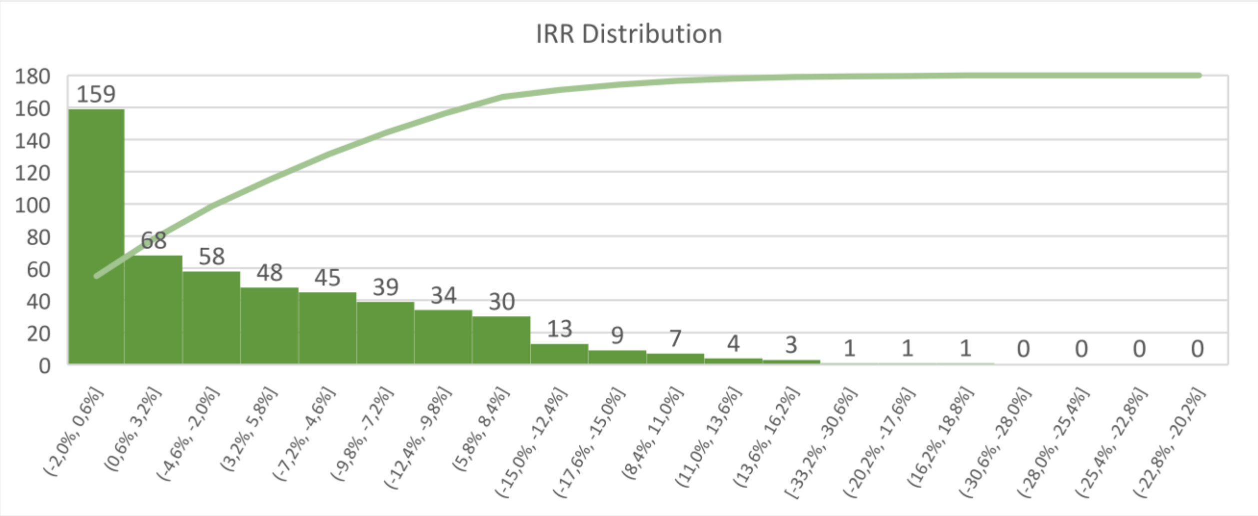


Figure 3-22 Pareto diagram, showing the distribution of IRR

As can also be seen, there are more negative outliers than positive, and the negative outliers are more extreme than the positive outliers. This could in turn indicate that the outliers, i.e.. the "experimental" projects in e.g. Germany are "expensive" learnings for the investors. The percentiles shows the distribution of IRR; P(90)= 8,9%, P(70)=3,7% P(50)= 0,8% and P(25)=(4,4)%. To see all countries performance in 2018 and average, see appendix Table 8-9.

3.3.5.3 *Perodic comparison of 09'-15' versus 16'-19'*

This section will elaborate, with statistical significance, on the development shown in Figure 3-13. For this, we created two regressions, one with the data from 09'-15' (recall the 2nd and 3rd IRR wave from Figure 3-19) with n=141 and 16'-19' (recall the 4th IRR wave) with n=270. The purpose is to illustrate how the variables have developed through the three waves, albeit not precisely the same years, this choice of periods has been made to ensure a sufficient amount of observations to obtain statistical significance. The output of the two regressions can be found in appendix Table 8-4 and Table 8-5, their Q-Q plot in Figure 8-7 and Figure 8-8. Their histograms are in Figure 8-9 and Figure 8-10.

First thing that should be noted for 09'-15', is the intercept which is 0,57% lower in the latter period, which is in line with what can be observed in Figure 3-19. The variable OPEX has decreased 46,7%, creating more attractive returns. This is in line with what we displayed in chapter 4. The variables Depth and Distance to Shore, have all developed to a "more" negative influence on IRR, -3% and 110%, which is also in line with what can be observed in section figure 3-18 What can also be seen, with significance, is the positive improvement of capacity, improving 27% relatively. Looking at the same countries as above, it can be observed that USA and Germany both have developed negatively with a -34% and -97,6% development respectively. Canada (and France) was removed from the first period because of multicolinarity. Japan, Taiwan and China has also developed more negatively, -1,7%, -5,3% and -1% repectively.

3.3.5.4 Combining knowledge of the industry trend with the drivers influence on IRR: Case studies

We can conclude that, countries like Germany, USA, Canada are countries that our model estimates will have a (more) negative impact on the IRR compared to the other countries. This is mainly driven by low electricity prices and unattractive locations. If we consider the average electricity price, we can see that the bottom countries have average prices of 48%, 57% and 60% below the world wide average (over time), respectively. This is quite a lot. All three countries have capacity factors well above average and looking at their CAPEX factor it can be seen, that Germany has the highest value of all countries in the dataset, with an average of 1,62 whereas Canada and USA is just below average (1,17 and 1,27). This indicates that Germany has built parks far away from shore driving up CAPEX costs, but the high capacity factor has not outweiged the extra costs. As such, moving further from shore has been more of a cost driver than a revenue driver. Additionally, many of the German parks were developed in times where the general CAPEX costs were high, recall the high commiodity prices in 2006-2010. As such, the reason why Germany is performing badly is related to high CAPEX costs and low electricity prices. Given Germany's status as one of the first mover markets, it is interesting that the country has the second lowest average IRR of -9,8%. Germany has clearly done some very costly and experimental projects, but a central question is whether Germany harvest the benefits of the knowledge that is developed through these experimental projects or if it is the imitators or followers that are benefitting, by free-riding on the developed knowledge (Shenkar, 2010). If so, then perhaps it is better to be an imitator than an innovator in the market. The reason why the US and Canada ranks badly is due to their very low electricity prices.

On the other hand, it can be seen that Japan, Taiwan and China are the highscores with average IRR's of 10%, 8,3% and 2,7% respectively. Thus, they outperform the rest of the dataset by far, which on average has an IRR of 0,2%. We see that the main driver for the high IRR's is the high electricity prices. Japan's average electricity price is 53% above average, for Taiwan it is 60% and for China 30%. This is very high and has a significantly positive influence on IRR. Equal for the countries is also that they on average have relatively large parks, build primarily in the 3rd IRR wave, where CAPEX has be relatively low. This has allowed them to benefit a lot from economies of scale (see section 3.3.3). The Capex factor for the three countries are respectively 1,06, 1,33 and 1,05. As such, it is quite low for Japan and China whereas Taiwan ranks somewhere in the middle. The capacity factors for the countries are 36,1%, 46,4% and 37,8%, respectively. As such, Taiwan has a better capacity factor, but it is not enough to outweigh the extra costs. Therefore, the Japanese and Chinese projects gain better returns because they have lower costs even though Taiwan has higher electricity prices than China.

3.4 Conclusion of Key value drivers and IRR

The purpose of this chapter has been to answer the first sub-question: *Which drivers are most important for the financial returns and what can be learned from their historical development?*

We have analyzed how the different value drivers affects the project's IRR and we have looked at the distribution of IRR over time, across our 16 focus countries. From our regression analysis we can conclude that the most important drivers are respectively: Nameplate Capacity (+), OPEX (-), Capacity Factor (+), distance to shore (-) and depth (-). Albeit, we cannot observe the influence that electricity prices (+), CAPEX (-), decommissioning costs (-) and energy loss factors (-) have on IRR through the regression, we have tested them separately against IRR. Electricity prices has the biggest influence on IRR, followed by CAPEX and then the energy loss factor.

In regards to the historical development of the drivers, we can see that the industry has developed as an S-curve in different "waves", i.e. showing improvement in different tempi's. This matches the theory of technological development. We have found this to be a result of the industry's age, that is, it has and still is trying new ways to improve the profitability for example by moving sites further from shore to gain better wind conditions. We find that the relative increase in capacity factor from moving further from shore, more than offsets the relative increase in CAPEX. However, we find that the capacity factor actually has decreased while the CAPEX factor has increased. This indicates that developers have not succeeded in improving the capacity factor when moving further offshore.

Overall, we observe a positive trend in the profitability of the industry over time (Figure 3-19 & Figure 3-22), but with great geographical differences. High scoring countries are Japan, Taiwan and China who all have the common trait that they have built large parks in a period with low CAPEX fairly close to shore. Furthermore, the countries have electricity prices significantly above average. Bottom scoring countries are Germany, Canada and USA. Common for these countries are low electricity prices significantly below average. Furthermore, Germany has by far the highest CAPEX factor of all countries resulting in high CAPEX costs. Meanwhile, the projects in Germany have also been relatively small, hence not benefiting as much from economies of scale. USA has the biggest projects, but the lowest electricity prices. For the US, their low electricity prices in relation to OPEX, gets enforced by their large projects, which gives the lowest IRRs. This might sound contradicting to economies of scale, but does in fact highlight how EOS work in the model; the electricity price has to be relatively more positive than the OPEX and CAPEX, since all is driven by nameplate capacity. If not, then economies of scale actually work against IRR and decreases as capacity increases. Furthermore, we observe that significant cost reductions are projected due to the learning curve. However, our literature review reveals that previous projections have been overly positive. The investor should note this when looking at future projections.

Below, we present a summarizing matrix of average pretax-pre-subsidiary IRR and the key value drivers for our 16 focus countries. The numbers are weighted averages for the entire period (2000-2020).

Table 3-7 Overview of country specifications, entire period (2000-2020),All values are weighted averages

Rank	Country	IRR	Capacity (MW)	Capacity Factor	Price/kWh	Depth	Distance from shore	CAPEX	CAPEX Factor
1	Japan	10,02%	368	36,1%	0,10	-11	5	2.829	1,06
2	Taiwan	8,26%	492	46,4%	0,11	-27	24	3.178	1,33
3	Ireland	7,53%	597	57,8%	0,06	-13	11	2.437	1,08
4	Denmark	4,01%	229	55,3%	0,06	-11	11	2.807	1,06
5	China	2,74%	247	37,8%	0,09	-10	11	3.512	1,05
6	United-Kingdom	2,65%	502	55,1%	0,06	-24	36	3.163	1,34
7	Poland	1,45%	700	50,2%	0,07	-35	45	3.204	1,54
8	France	-0,33%	334	45,7%	0,05	-20	11	2.831	1,14
9	Estonia	-0,44%	621	47,7%	0,05	-13	13	2.826	1,09
10	Netherlands	-1,64%	369	52,6%	0,05	-16	31	2.833	1,20
11	Sweden	-2,88%	411	46,9%	0,05	-12	16	2.943	1,11
12	Greece	-3,19%	138	33,8%	0,06	-10	6	3.044	1,05
13	South Korea	-5,72%	364	34,1%	0,05	-14	6	2.875	1,11
14	Canada	-9,15%	629	50,4%	0,03	-16	16	2.965	1,17
15	Germany	-9,77%	301	58,0%	0,04	-30	58	3.422	1,62
16	USA	-13,25%	985	49,5%	0,03	-21	26	2.992	1,27
	Worldwide	**0,22%**	**385**	**45,27%**	**0,07**	**-17**	**21**	**3.184**	**1,2**

It is important to note, that this table does not highlight the outliers as we use weighted averages.

Key take aways from the matrix are and chapter 3 are:

1) Industry performance has developed in an s-curve with 4 waves
2) Great national differences in IRR and electricity prices
3) Parks have increased in size with a CAGR of 10,6%

4) CAPEX has experienced great fluctuations as the industry has experimented with innovative projects, i.e. locations. Further we see that CAPEX is sensitive towards commodity prices of steel and cobber.
5) OPEX increased initially, as the supply chain first had to be established. As the supply chain has matured OPEX has slowly decreased.
6) Projects move further towards sea, in pursuit of better winds. This drives cost up and we have found that despite the effort, little increase in wind quality is achieved.
    a. Even though better winds are not achieved, we find in the regression that it is worth pursuing, accounting for the tradeoff.

4 Support schemes

4.1 Purpose of this chapter

The purpose of this chapter is to answer the second sub-question: *How does support schemes influence offshore wind projects?*

In chapter 3, the value drivers for the pre-tax and pre-subsidy IRR was analyzed. Furthermore, global industry trends were analyzed in relation to their influence on the pre-tax and pre-subsidy IRR. However, the analysis did not account for the support schemes, which has a major influence on the project-value. Therefore, the point of this chapter is analyze these in relation to how they influence offshore wind projects.

Subsidy schemes are different from project to project but within countries they have the same overall structure. This makes them difficult to quantify as you need to know the specifics for each project, often non-disclosed information. As a consequence, we take a high-level, qualitative approach to assessing the support schemes in our 16 focus countries. Hereafter, we quantify the value of the support schemes in five selected focus countries to give the reader an understanding of how support schemes influences the IRR.

4.2 Support schemes

As it can we seen in appendix Table 8-10, we observe four different overall tariff structures: fixed feed-in (FiT), fixed-premium (FiP), Quota system and contract for difference (CFD). This indicates that a dominant design does not exist.
We do however see some global trends in the tariff structure. Most European countries use a fixed premium tariff (70%) whereas most Asian countries uses a fixed feed-in tariff (75%). We do not observe any geographical trend with the Quota-system (South Korea, Sweden, and the United States).

We have chosen to separate our analysis according to the overall tariff structure. We believe that this gives the reader the best overview of the country-specific variations. Each section starts with an explanation of the tariff with focus on the risk/return properties and their impact on the investor. Hereafter, we compare the country-specific differences and rank the countries according to financial attractiveness for investors.

4.2.1 Feed-in tariffs (FiT)

The FiT is the main support scheme for 6/16 of our focus countries where 1 are found in Europe, four in Asia and the last being Canada (Appendix Table 8-10).

The FiT is a direct revenue support scheme usually spanning the entire, or majority, of the project lifetime, providing a rate of compensation for each unit of electricity generated (Couture & Gagnon 2010). The FiT's typically include:

1. Guaranteed grid access
2. Long-term power purchase agreements
3. Fixed Purchase Prices

As such, the two main appeals of FiT policies for investors certainty of being able to sell all produced electricity to a fixed price over the project lifetime, which gives a low risk. As the income side is relatively fixed, the profitability of projects is heavily dependent on investor's ability to control their costs and increase the park's efficiency (Deloitte, 2011). This also means that operators have little incentive to match demand in the market, and rather keep producing even though demand is low. Therefore, the feed-in tariff scheme has been criticized for having few market-based incentives and for often resulting in overcompensation (Couture & Gagnon, 2010). FiT can be illustrated as the following:

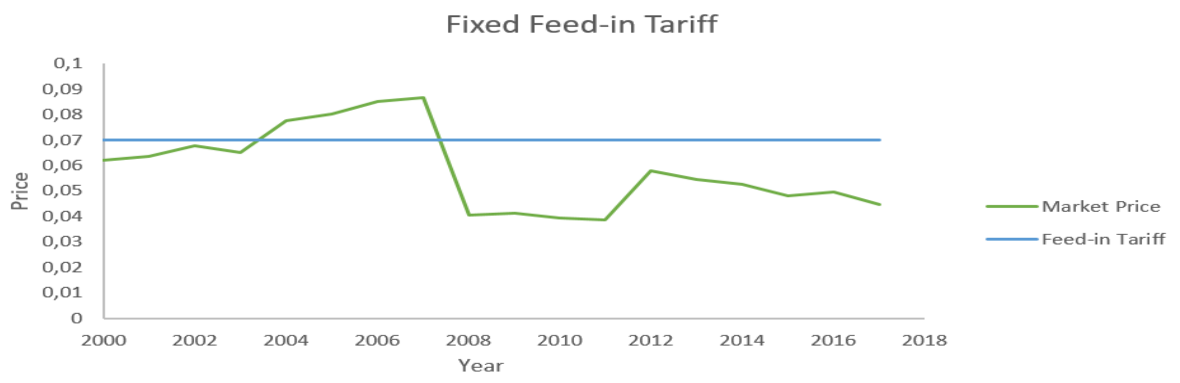


Figure 4-1 Feed-in Tariff visualized, own creation

The blue line indicates the fixed price that developers receive, which is in this case set to 0,07$/MW for purely illustrative purposes. This is called the remuneration level. As can be seen, whenever the market price is below the remuneration level, the developer will be receiving the difference by the government. This is known as the FiT surcharge. If the electricity price rises above the remuneration level, the developers forego the abnormal profits. However, the remuneration level is typically set to an amount such that this rarely happens (Prässler & Schaectele, 2012).

Comparing countries with FiT

Within the 6 countries, we observe a great deal of similarities. In all countries, offshore wind parks have guaranteed grid access, long-term power purchase agreements and a fixed purchase price. As such, reality seems to match theory and parks in these countries would secure a certain revenue stream for the eligibility period which is 20 years in all the countries except for Ireland where it is 15. Furthermore, we observe that the cost of grid connection is carried by the government in the Asian countries and not in Canada and Ireland. As discussed in chapter 3, grid connection constitutes approximately 15% of the initial CAPEX investments, which means that this feature greatly reduces the initial investments and is another very attractive feature of these countries.

A central difference observed between the countries is the way in which the remuneration level is determined. This is essential for the attractiveness of the scheme as investors wants as high a remuneration level as possible (European Commission, 2017). We observe two different methods used within the countries distributed as following:

Remuneration Level	Country
Price Scheme	Japan, China, Taiwan
Quantity Scheme	Ireland, Canada, India

The remuneration level is also sometimes determined based on the LCOE of the technology or the "avoided costs" to society in terms of CO2 emission, pollution and so on (NREL, 2010). However, we will not go in-depth with these methods as none of our focus countries use it. In the following sections, we will analyze and discuss the various approaches used by our focus countries to determine the FiT payments.

4.2.1.1 Price Scheme

In a price scheme, the remuneration price is predetermined and stated in the concession offer. As such, it is not determined by the market-forces and publicly disclosed before the investors make their bids on the concession (European Commission, 2017). This provides a great deal of security for investors as they can accurately determine the return on their investment before placing their bid, since they only need to assess the wind resource, i.e.. the capacity factor and size of the park to find both a relatively precise revenue and investment cost (Couture & Gagnon, 2010). From the government's perspective, the price scheme is challenging as the remuneration level should be set to so that it attracts enough investors to ensure the desired capacity expansion, but not so high that it overcompensates investors. Due to the asymmetric information between the public and private sector the governments often underestimate the cost-efficiency of the developers and set the remuneration level too high. This has been the case in countries such as Spain, Czech Republic, and Greece which in turn has been one of the central drivers for the move to the more market-based compensation model: the Quantity Scheme (Lipp, 2007; Deloitte, 2011).

4.2.1.2 Quantity Scheme

In the quantity scheme, the governments determine the remuneration level on the background of the bids they have received on the concession. As such, the remuneration level is based on the results of an auction or bidding process, which can help inform governments about the cost efficiency of the project bidders. After receiving the bids, the government negotiates a company-specific tariff with each of the project bidders until the desired total capacity expansion is reached. As such, it is a more market-driven approach since the tariff is determined through negotiations (Deloitte, 2011). The method is attractive for governments since it ensures that the state and thus the electricity consumers do not overcompensate investors. However, the model is imposes more uncertainty for investors since they bid on market terms, and are "forced" to bid low to win the concession (Couture & Gagnon, 2010).

4.2.1.3 Comparison

Due to asymmetric information, the pricing scheme is more favorable for the investor and less so for the state. For the quantity scheme a marked based auction forces investors to lower their bids, i.e.. lowering the price.

Therefore, the price scheme is considered more attractive than the quantity scheme for the investor. This is backed by the conclusion of a study conducted by Deloitte (2011), where investors were asked what they prefer, and the price scheme won by far. For this reason, China, Japan, and Taiwan are perceived as more attractive than Ireland, Canada, and India. However, since the remuneration level in the price-scheme is unique for each concession, we cannot say anything general about the difference of attractiveness within these countries. Since we cannot find any other national differences, we are forced to classify them as equally attractive. Ireland is clearly the least attractive FiT country do to the shorter eligibility period and since the remuneration level is determined using the quantity scheme. However, we cannot distinguish between the support scheme in Canada and India and are once again forced to rank them equally. We arrive at the following rankings:

Table 4-1 Comparison of FiT Schemes

Country	Unique Feature	Ranking
Japan	Price Scheme Paid Grid Connection	1
China	Price Scheme Paid Grid Connection	1
Taiwan	Price Scheme Paid Grid Connection	1
Canada	Quantity Scheme	2
India	Quantity Scheme	2
Ireland	Quantity Scheme 15 years eligibility period	3

4.2.2 Feed-in premiums (FIP)

As previously stated, the FIP is used in 7/10 of our EU countries and is not found in any of our focus countries outside the EU. In the FIP, the developer receives a fixed premium above the market price sometimes combined with a minimum/maximum price to reduce risk, or a sliding premium with variable levels depending on the evolution of market prices (Schallenberg-Rodriguez & Haas, 2012). The premium is the difference between the spot market prices and the received price (European Commission, 2017). The FIP is praised for offering investors a degree of revenue stability while still maintaining market-based incentives as developers are exposed to fluctuating electricity prices and need to adapt a more efficient behavior in terms of producing when demand is high/low (Hiroux & Saugan, 2010). However, this argument does not hold for intermittent energy sources where producers cannot effectively control their supply, hence match supply/demand. This could argue for this model to be more fitting for other non-intermittent RES sources that can be effectively stored such as hydropower (Deloitte, 2011). In the graph below, the three main FIP structures are graphed:

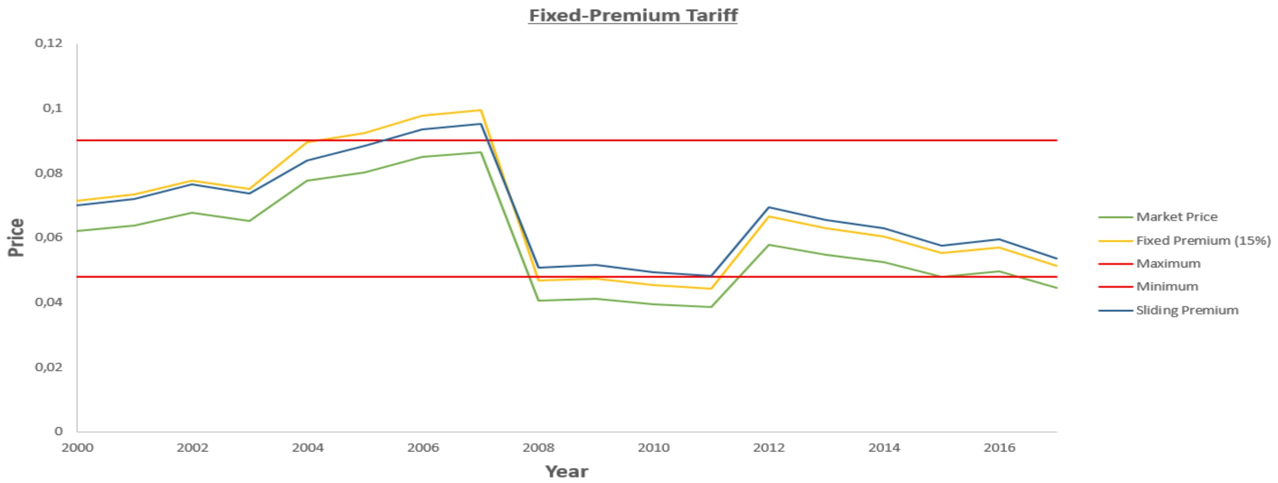


Figure 4-2 Feed in Premium illustrative example

In this example, the fixed premium is set to 15% purely for illustrative purposes. As it can be seen, the fixed premium always ensures investors a price above the market price. The premium is fixed and independent of the market price which means that the compensation is largest when the market price is high and vice versa. Therefore, the FIP premium is riskier than the FiT as the developer can potentially receive very low payment rates when the market price is low. To avoid a large divergence between profits and losses some countries have implemented payment caps/floors that defines the price interval that developers can receive. Floor limits are particularly appropriate for investors as they can determine the minimum return on their investments accordingly. In the example above, the investor would receive a fixed price of ~0,05 in year 2008-2010 when the market price is low.

The FiP lowers the risk of overcompensation and ensures that developers are compensated when they need it the most. The chance of abnormal profits is highest with the normal FiP and both modifications reduces the potential upside and downside. In general, earnings are much more volatile in any type of FiP model than in a FiT scheme. This has been known to subsequently lead to higher risk premiums (Schallenberg-Rodriguez & Haas, 2012).

In general, we observe a much higher degree of local adaption with the FiP countries than with the two other subsidy structures. The countries generally have two things in common. First, the premium is determined through a tender offer process, except for France where the premium is determined through a formula. A tender offer resembles the quantity-scheme of the FiT model and essentially means that the premium is determined by market competition in the concession offers (ECOFYS, 2013). Second, all countries except for Estonia uses tax-incentives on top of the FiP premium as additional support. Due to the high degree of local adaption, we believe that the reader gets the best overview if we review the countries one by one.

In general, we consider it an attractive feature to have a fixed and "secure" cash flow. This is found in Spain and Estonia. Estonia does however rank terribly in terms of other parameters such has eligibility period and additional support mechanisms. Therefore, it is considered the worst place FiP country to invest in.

Additionally, the eligibility period is considered an important feature as it limits the time for which the developer is exposed to market risk. Here Germany is the clear winner and all other countries (except Estonia) rank equally. Furthermore, who pays for grid connection is considered an essential value driver since it constitutes such a large cost component in the construction phase. This is the case in Denmark, Germany, and the Netherlands.

We observe two different eligibility periods in our focus countries with the FIP tariff. The eligibility period for Germany is 20 years whereas the period is only 15 years for the other FIP countries (DK, France, The Netherlands, Spain). This makes Germany more attractive as the country provides higher and secure compensation to the investors. Like with the FiT, subsidies can either be tied to the production, expiring after a certain produced amount or to a predetermined period where after it expires. We find that all the countries in scope use the latter. Our challenge when trying to quantify the differences of the countries is the information on premium percentage level countries. This is because the percentage is determined in the bidding process must like in the quantity scheme.

Below a table to summarize the findings of each country's unique characters followed by a deep dive in each of the countries unique characteristics.

Comparison

The table below summaries the unique features in the countries. Furthermore, the countries have been ranked in terms of attractiveness for an investor.

Country	Unique Feature	Ranking
Germany	• Longest eligibility period (20 years) • Premium reviewed each month • Paid grid connection • Favorable government loans	1
Denmark	• Capped support level, but no floor price • Additional bonus support in initial years • Paid grid connection • Favorable government loans • Fine for too slow development	2
Spain	• No support cap and no chance of premium reduction • Participation guarantee	3
Netherlands	• Sliding premium + capped maximum • Paid grid connection	4
Greece	• Sliding Premium • Capped support level based on production	5
France	• Yearly support reduction based on industry cost levels • Protectivity policies	6
Estonia	• Yearly cap on support based on the market production • Additional support beside FiP is prohibited • Shortest eligibility period (12 years)	7

Germany

In Germany, all parks above 10 MW are eligible for a FIP for 20 years, which is the longest period of all FiP countries. However, the German model is also the only one where the premium level is reviewed every month to reflect cost reductions[17]. This means that for most technologies, the tariff levels will decrease in regular periods of time, which creates an uncertainty for investors. Therefore,

[17]http://www.res-legal.eu/search-by-country/germany/single/s/res-e/t/promotion/aid/premium-tariff-i-market-premium/lastp/135/ 1/4 13:00

the longer support period can be viewed as a compensation for the support reductions. Furthermore, the cost of grid connection is covered by the government[18]. Lastly, Germany is well known for their favorable loans to RE developers (Interview, Peter Staudt, see appendix A.2)

Denmark

In Denmark, the remuneration level has a capped maximum, but has no capped floor price. Therefore, operators know the maximum support level they can theoretically obtain but cannot determine the minimum return on their investment. The eligibility period is 15 years and power plants receive an additional bonus support for the first 42.000 full load hours[19]. This is considered a strength to the model as it ensures that power plants get more support in the period where it is needed the most. Furthermore, the developers are eligible to favorable loans guaranteed by the Danish government[20] who also pay for grid connection[21]. Lastly, the Danish concessions are the only ones found to include a fine or subsidy deduction if windmills are not grid connected before a certain date and a fine if the winner of the tender-offer chooses to opt out of the concession after 6 months (Deloitte, 2011).

Spain

Spain is the only country where the FiP doesn't have any local adaption that is different from the theoretical examples stated above. The premium is determined through a tender process and is fixed for 15 years. As such, the model has the advantage over the above-mentioned countries that the premium is fixed and is not reviewed on an ongoing basis. This provides safety for the investor. the only unique feature of the model that can be found is that the developer must pay a participation guarantee of 60 €/kW, when winning a concession[22]. As such, Spanish projects have an additional cost factor that are not seen in any of the other countries.

Netherlands

The Netherlands uses both a sliding premium and a capped maximum support. Both adaptions ensure that governments do not overcompensate investors but are unattractive features for the investor for

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18 http://www.res-legal.eu/search-by-country/germany/tools-list/c/germany/s/res-e/t/gridaccess/sum/136/lpid/135/ 1/4 14:00

19 http://www.res-legal.eu/search-by-country/denmark/single/s/res-e/t/promotion/aid/premium-tariff-law-on-the-promotion-of-renewable-energy/lastp/96/ 3/4 09:30

20 http://www.res-legal.eu/search-by-country/denmark/single/s/res-e/t/promotion/aid/loan-loan-guarantees-for-local-initiatives-for-the-construction-of-wind-energy-plants/lastp/96/ 4/4 09:30

21 http://www.res-legal.eu/search-by-country/denmark/single/s/res-e/t/gridaccess/aid/connection-to-the-grid-8/lastp/96/ 3/4 10:30

22 http://www.res-legal.eu/search-by-country/spain/single/s/res-e/t/promotion/aid/feed-in-tariff-regimen-especial/lastp/195/ 3/4 11:30

the exact same reasons. The eligibility period is 15 years and grid connection are paid by the government[23].

Greece

Like the Netherlands, Greece also uses a sliding FiP, but without the capped maximum. Furthermore, we find that Greece is the only country that has a cap on the amount of support the wind farm can be obtained based on the production (200 MW/year)[24]. This is considered an unattractive feature of the model since large parks are likely to reach this maximum. The eligibility period is 15 years and grid connection are not paid by the government[25].

France

In France, the premium is calculated according to a formula considering various variables such as the cost of RES installations and the reference market price over a given time. The premium is fixed for 20 years and 60% of the tariff is subject to a yearly reduction. The reduction is determined on the background of yearly industrial production costs to ensure that the tariff follows the industry evolution[26]. As such, the French model is a combination of a sliding premium and a normal FiP model. The attractiveness of the model is rather unclear as it is determined through a formula. However, according to Peter Staudt from PensionDanmark, France have one of the weaker support structures and is generally not considered an attractive market in their beliefs (Appendix A.2). Furthermore, we were told that France heavily protects the industry by favoring domestic technologies and developers. According to Peter Staudt, this means that concessions are difficult for foreign companies to win which in turn creates a less competitive industry in France resulting in higher developing costs (See appendix A.2).

Estonia

Estonia is the only country to use a yearly cap on the amount of support that can be obtained, which is based on the quantity of total energy produced by all wind power plants. Essentially, all support is suspended for the current calendar year as soon as the generation of a total amount of 600 gWh

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[23] http://www.res-legal.eu/search-by-country/netherlands/tools-list/c/netherlands/s/res-e/t/gridaccess/sum/172/lpid/171/ 4/4 12:35
[24] http://www.res-legal.eu/search-by-country/greece/ 4/4 13:31
[25] http://www.res-legal.eu/search-by-country/greece/tools-list/c/greece/s/res-e/t/gridaccess/sum/140/lpid/139/ 4/4 13:58
[26]http://www.res-legal.eu/search-by-country/france/single/s/res-e/t/promotion/aid/premium-tariff-complement-de-remuneration-par-guichet-ouvert/lastp/131/ 3/4 16:30

electricity from wind energy has been supported[27]. This gives uncertainty to the developers as they do not know how much support they will get or when it will be cut off. Furthermore, the electricity generated by a wind power plant is not eligible for support if the plant operator has received other investment subsidies from the state for the relevant generating installation[28]. Since Estonian parks rank highly in terms of park size (4th), this is considered a weakness to the Estonian model as all other countries use some sort of additional financial support on top of the FiP. Lastly, power plants are only eligible for 12 years of support in Estonia, which is the shortest eligibility period of all the countries across the three subsidiary structures.

4.2.3 Quota system

We observe the quota system in three different countries: Sweden, South Korea, and the United States. The system originally stems from the UK, who had it for more than 10 years until it was effectively removed in 2017[29]. The Quota system is based on Renewable Obligation Certificates (ROC) that are given to RE producers to sell in combination with their produced electricity to the grid operators. At the same time, the grid operators are obligated by the state to buy a certain number of certificates from RE producers and once a year it is determined to what extent they have met their ROC requirements (Deloitte, 2011). If they have not managed to buy enough quantity of ROC certificates, they have to a financial penalty. The penalties are gathered in a public fund and distributed to the RE producers that have managed to meet their ROC requirements (Komor, 2004). This gives grid-operators a high degree of incentives to meet their ROC requirements. The Quota system is praised for being the most market-driven support schemes as the price of the ROC is determined in the free market (Mennanteau, Finon, & Lamy, 2003).

If many energy suppliers fall short of the ROC demand, the financial penalty increases and vice versa. Furthermore, the quantity of RE energy that grid operators must buy is determined by the government, but the decision as to what source to buy from is up to the grid operator. This means that the RE technologies are effectively directly competing and the cheapest technology are favored by the grid operators (Mitchell and Connor, 2004).

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[27] http://www.res-legal.eu/search-by-country/estonia/single/s/res-e/t/promotion/aid/premium-tariff-1/lastp/123/ 4/4 12:40

[28] http://www.res-legal.eu/search-by-country/estonia/single/s/res-e/t/promotion/aid/premium-tariff-1/lastp/123/ 5/4 12:55

[29] https://bit.ly/2VlivEt 5/4 12:47

This incentivizes RE technologies to be as cost efficient as possible. Having guaranteed prices for the RE producers (as in the FiT) has a negative effect on competition and lowers the incentive to reduce costs (Frondel et al., 2010). (Frondel, Ritter, Schmidt, & Vance, 2010) However, the counter-argument is that free market competition does little to promote emerging high-cost technologies and thus the system does little to overcome the market deficiencies (Prässler & Schaectele, 2012). The quota system can force high-cost technologies out of the market, even if the potential of their long-term innovation is evident (Kwon, 2018). According to Lipp (2007) the UK and Sweden both have struggled on this behalf regarding the offshore wind industry. Sweden has subsequently chosen to keep the system whereas the UK replaced it in 2017. Therefore, some countries such as South Korea[30] have implemented different quota systems for the various RE technologies. Effectively this means that the grid operators must buy a certain amount from each RE technology determined by the cost and perceived potential of the technologies (European Commission, 2017). Therefore, the decision is no longer entirely up to the grid operator and emerging technologies gets an advantage. Additionally, the Quota system has been criticized by developers for being too risky as neither the volume nor the selling price can be determined post ante (Kwon, 2018). It can be stated, that developers want as high a quota obligation fine as possible because it will give grid operators the most incentive to buy energy from them. However, the fine is determined the same way as in the two other quota countries.

We observe two similarities in the quota systems. The eligibility period is 15 years for all countries and the grid connection is not paid by the government[31,32,33]. Other than that, we find a high degree of local adaption and therefore we find it necessary to take the countries one by one.

Comparison

From the below, we conclude that South Korea is the most attractive of the Quota systems as it favors emerging, high-cost technologies such as off-shore wind energy over other RE's. other than that, the systems are very similar as they all have the same eligibility period, tax credits etc. We rank Sweden as the second most attractive as investors can get investment support for pilot projects whereas we find no unique features in the United States. We emphasize that the rankings are debatable as we cannot find the size of the tax credits, which potentially could put the US in second place.

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[30] https://bit.ly/2GYbiRX 10/05 09:45
[31] https://bit.ly/2GYbiRX 10/05 10:30
[32] https://bit.ly/2kyaa9E 10/05 11:13
[33] http://www.res-legal.eu/search-by-country/sweden/single/s/res-e/t/promotion/aid/quota-system-1/lastp/199/ 10/05 11:15

We arrive at the following rankings:

Country	Unique Feature	Ranking
Sweden	Investment support for pilot projects	2
South Korea	Priority to emerging high-cost technologies	1
United States	No unique figures	3

Below a deep dive in each of the countries unique characteristics.

4.2.3.1 Sweden

In Sweden, grid operators are obligated to buy a fixed percentage renewable energy based on the amount of electricity that they process. As such, larger grid operators have a higher obligation and vice versa. The quota obligation has been determined all the way to 2045, which provides some political stability for the investors. Furthermore, the quota obligations are quite high, which makes sense given that Sweden has the highest RE target of all our countries of 49% by 2020[34]. This is considered a very attractive feature for investing in Sweden.

However, Sweden does not use different Quota systems for RE technologies, meaning the system does little to help emerging technologies such as wind energy. This matches the criticism proposed by Lipp (2007) above. Furthermore, it does not help that Sweden is very strong in hydropower, which could possibly outshine the potential of offshore wind energy for grid operators (Johnson & Jacobsson, 2001). Lastly, the quota obligation fine is 150% of the weighted, average certificate value during the applicable obligation period[35].

4.2.3.2 South Korea

The Quota system in South Korea was implemented in 2012 following 10 years of using a fixed feed-in tariff[36]. What makes the South Korean system unique is that the country uses a different quota for different RE technologies. The amount of electricity that grid operators must buy from different technologies is determined using a multiplier that takes costs into account. The multiplier is updated every four months to ensure that cost developments are considered[37]. As such, the developers can ensure a higher sold quantity, which provides safety to the investment case. Currently offshore wind

[34] https://bit.ly/2PSQZZn 10/05 11:25
[35] http://www.res-legal.eu/search-by-country/sweden/single/s/res-e/t/promotion/aid/quota-system-1/lastp/199/ 10/05 12:20
[36] https://bit.ly/2GYbiRX 10/05 11:140
[37] https://bit.ly/2GYbiRX 10/05 11:37

has the highest multiplier value, indicating that South Korea wishes to promote offshore wind. This makes it attractive to invest currently.

4.2.3.3 US

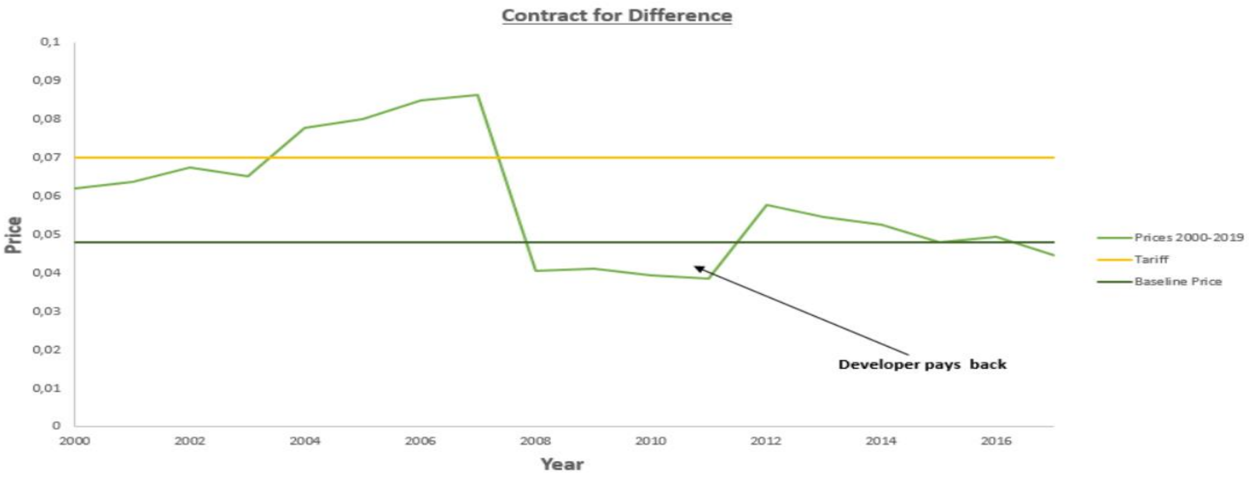
The US system is difficult to assess because the quota-system is determined at the state level. As of 2019, 29 states have adopted a quota-system and no two systems are the same.[38] As such, investors must assess the concrete support structure in the respective state. Since Rhode Island and Massachusetts are two of the main states within off-shore wind energy, we have chosen to focus on them (Irena, 2017). The states shares a lot of commonality since offshore wind energy doesn't get prioritized, which in turn makes US an unattractive market for investors[39,40]. Their main difference is the level of ambition in their RE goals where Massachusetts has committed to the highest % of RE energy[41][42]. This could mean that the possibilities for future expansion is best in Massachusetts. However, since both states are relatively new to the wind industry and both have plenty of potential sights, this is not considered an issue so far. The financial fine for not meeting the quota is a little higher in Massachusetts (68,95$/MWh) than in Rhode Island (67,07$/MWh), but it is unclear whether this has an influence on the investor[43][44].

4.2.4 Contract for difference (CFD)

The CFD model is only used in the UK for our focus countries. The model is a variation of a FiT where the tariff consists of a base price and a remuneration level. If the market price is above the base tariff, the developer will receive the remuneration price. However, if the price drops below the basis price, developers must pay back the difference between the basis price and the market price (European Commission, 2017).

[38] http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx 10/05 11:118
[39] http://www.energy.ri.gov/renewable-energy/wind/ 10/05 11:20
[40] https://www.mass.gov/service-details/offshore-wind 10/05 11:32
[41] http://programs.dsireusa.org/system/program/detail/1095 10/05 11:37
[42] http://programs.dsireusa.org/system/program/detail/479 10/05 11:55
[43] http://programs.dsireusa.org/system/program/detail/1095 10/05 12:05
[44] http://programs.dsireusa.org/system/program/detail/479 10/05 12:13

This is illustrated below:



The model is attractive as it offers a guaranteed payment that ensures a stable revenue like the FiT model. However, it gives developers more uncertainty and market-risk exposure as they potentially risk having to pay back money if the market price gets below the base price. This is subsequently what makes the model attractive for governments as it reduces the risk of overcompensation when market prices are excessively low (ECOFYS, 2013). The eligibility period is 15 years and the cost of grid connection is not covered by the government.[45]

4.3 Quantifying the value of support schemes

Throughout this thesis, we have referred to the pretax and pre subsidy IRR, meaning we have delimited ourselves from analyzing the influences of support schemes statistically. Our analysis above, took a qualitative approach to analyzing the influence of support schemes, but in this section, we attempt to quantify the importance of support schemes to better grasp their influence on IRR. As mentioned in section 4, support schemes vary from project to project but share common trades between countries. As such, it is very difficult to find the specific support schemes for the individual project as it would require access to information regarding the specific concessions, which is often confidential. Therefore, we use national averages of the subsidized electricity price/MW/year and assume that all parks for the given country in the given year receive that price for the quantity electricity produced. We have found the subsidies for China, Germany, Denmark, The Netherlands and Ireland for 2012-2017. We believe that the calculations provide the investor with relevant

[45]http://www.res-legal.eu/search-by-country/united-kingdom/single/s/res-e/t/gridaccess/aid/connection-to-the-grid-11/lastp/203 12-05 10:36

information regarding the influence of support schemes on the project value, albeit remaining a proxy and should only be used indicative.

In the period and for these countries we have a total of 100 parks for which we compared the IRR including and excluding the support schemes. These values are listed in Table 8-7 and Table 8-6. Our calculations are quite simple. We merely "replace" the market price with the subsidized electricity price (FiT scheme) in our valuation model and use this price for the next 15 and 20 years depending on the country (15 years for DK, NL, and IR and 20 years for CH and DE).

Table 4-2 IRR difference for IRR with subsidies vs IRR without subsidies. Based on Table 8-6

Year	China	Germany	Denmark	Netherlands	Ireland	Average
2012		-268%				-180%
2013	-83%			-3024%		-196%
2014	-119%		-98%			-117%
2015	-51%	-177%	-82%			-73%
2016	-48%		-67%			-69%
2017	-54%		-55%	-95%	-43%	-72%
Average	-60%	-207%	-67%	-129%	-51%	-83%

As can be seen, subsidies have a major impact on IRR. In 2012 the IRR excluding subsidies is on average 180% lower than the IRR including subsidies. In 2013 it was 196% and from here on, we see a decreasing trend indicating a decreasing dependence on subsidies across the five countries. The parks without subsidies all have the same thing in common; they either have negative IRR or close to 0%. However, when subsidies are included, they all have a positive IRR, which clearly shows the importance of subsidies for the investment case. Looking at the respective countries it can be observed that there are great national differences in how big the influence of the support scheme is. This can be explained in three ways: either the country has attractive support schemes, the projects in the country are inferior thus giving the subsidy a relatively higher influence or both. We see that Germany is the most sensitive countries to subsidy schemes. Parks are two times more attractive with subsidies than without and they go from having a very negative IRR to the most positive IRR. In section 3.2 we found that the German sites were quite unattractive with the third lowest average IRR's of all our focus countries. Therefore, it is fair to say that Germany has bad project sites, but attractive support schemes that combined ultimately gives a quite attractive IRR for investors. We see that the Netherlands are the second most sensitive country to IRR. Since we found projects in the Netherlands to be moderately attractive, the significant difference must be because of attractive subsidy schemes in the Netherlands. The same is the case with the Danish sites and the Irish sites, except they rank a little higher in attractiveness without subsidies. The impact of the subsidies is not as significant in China, which seems to contradict the findings in section 4.2, where we found the Chinese support schemes to be the most attractive. This shows the shortcoming of the analysis of section 4.2. the analysis does not include real numbers hence we do not know the real value of the support schemes. Therefore, we must state that our rankings of the attractiveness of support schemes can be quite misleading.

In summary, the above analysis shows that:

1. Support schemes have a major influence on the project value, but the influence has decreased over time
2. Germany, The Netherlands, Denmark and Ireland are very reliant on support schemes whereas China is not as sensitive to changes in support schemes
3. The major setbacks of the findings in section 4.2 is that they are not based on real values, which could lead to biased rankings

A mismatch in the design of support schemes

We observe a clear mismatch as to how support schemes are optimally designed in the eyes of the government and in the eyes of the investor. Investors prefer the safe support schemes where they are exposed to the least amount of market risk, but governments prefer more market-based approaches as it reduces the risk of overcompensation. Therefore, governments clearly face a trade-off as they want to reduce the producer surplus as much as possible to reduce the cost carried by society, but still must create an investor environment that is attractive enough so that they obtain the desired capacity expansion. In this regard, governments must consider that most developers are large conglomerates looking for investment opportunities all over the world. Therefore, they cannot dictate the terms as it will force investors to invest somewhere else. Additionally, investments in RE is highly correlated, since institutional investors and banks often have funds set aside with the specific purpose of investing in RE's because of the steady, predictable returns and the goodwill from the public (Wind Europe, 2017). This means that if support schemes change and investing in offshore wind energy becomes less attractive, it can drive investors to invest in other RE technologies such as solar – or geothermal energy. Therefore, support schemes can essentially be boiled down to how the economic welfare should be distributed, which relates to the relative bargaining power of governments and developers. Governments need to obtain a desired capacity expansion and therefore they need to create an investor environment that is attractive enough such that the desired capacity expansion is obtained, but not too attractive as to overcompensate developers. Regarding the future of support schemes, we find it likely that the size of support schemes will diminish. This is because governments determine the size of the support schemes according to the desired capacity expansion and the compensation that investors require in order for the investment to be attractive. Therefore, as nations approach their RE goals and the industry matures, the support schemes are likely to decrease. However, a modern market can also be seen as a positive aspect, as it entails diminishing costs based on e.g. previous learnings and mature supply chains.

4.4 Future prospects of support schemes

As countries get closer to their national RE goals, the size of the support schemes is likely to diminish. According to Meyers & Kent (1998), the point of support schemes is to use public finance to create a temporary carrot that attracts corporate finance with the purpose of accelerating investments in industries that are in the public interest to promote, until enough innovation has taken place for the industry to be sustainable on its own. This means that as the industry evolves the IRR (excluding subsidies) increases and the risk of investment decreases leading to a lower cost of capital and a smaller required size of the support schemes. When the IRR meets the investors hurdle rate, the support scheme may no longer be needed as the industry is cost competitive on its own. As such, support schemes should theoretically follow the industry lifecycle and be gradually reduced as the industry matures (Myers & Kent, 1998). Therefore, investors face another trade-off: Investing early in a market to ensure attractive support schemes or postpone the investment and invest in projects that are more attractive on a standalone basis but simultaneously more risky due to the lack of government support.

4.5 Conclusion of support schemes

The purpose of this chapter was to answer the second sub-question: *How does support schemes influence offshore wind projects?*

Based on the risk/return features of the support schemes, we consider the FiT tariff to be most attractive due to the safety it provides to investors. This is especially the case when the price-scheme is used.
Hereafter comes the CFD tariff, which also offers a high degree of safety for investors, but with a little more market-exposure due to the baseline level.
In third-place comes the FIP tariff as it provides investors with a relative degree of revenue stability, whilst maintaining a high degree of market exposure.
In last place, we rank the Quota system as it offers neither price nor quantity security for investors.

A setback of our analysis is that we rank the support schemes based on a qualitative assessment. Therefore, we do not take the actually size of the support scheme into account. Our calculations in 4.3 indicates that we may obtain biased rankings when we don’t quantify the support schemes. For example, the Chinese support schemes is calculated to be quite low whereas the support schemes in Germany is found to be quite high.

Lastly, investors must take into account that support schemes are dynamic, hence constantly updated by governments in response to market development (REN21, 2015). Our calculations in 4.3 indicates that support schemes have a major influence on the project value, but the influence has decreased over time which is in line theory. This is something investors should carefully assess.

5 Investing in wind energy projects

5.1 The purpose of this chapter

The purpose of this chapter is to combine the findings from chapter 3 and 4 to *provide investors with recommendations on how to assess the key drivers and what tradeoffs should be considered when investing in wind energy projects.*

We will combine the knowledge from chapter 3 and 4 to provide recommendations on how to assess the key value drivers in relation to the future trends of the industry. Furthermore, we will highlight the trade-offs that the investor faces today when considering whether to invest now or later. This chapter will be structured according to:

- Trends in relation to revenue
- Trends in relation to costs
- The investment trade-offs
- Assess potential threats for the implementation of offshore wind energy

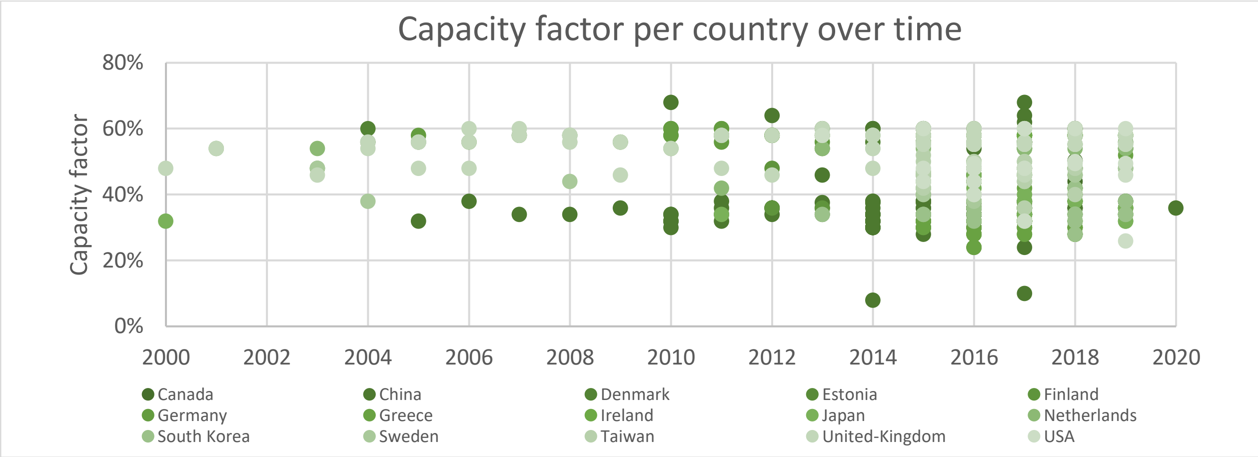
5.1.1 Assessing the revenue of offshore wind projects

As described in section 3.2.1, the revenue of an offshore wind project is a function of the price of electricity per mWh, the annual energy production and the support schemes. These factors will subsequently be addressed one by one.

5.1.1.1 Production of electricity

What we've found in our analysis is that the capacity factor is a central value driver for investors, when assessing where to locate parks and there is a clear incentive to optimize this factor by moving further from shore, as wind conditions are generally stronger, more consistent and without obstacles to interfere and "damage" the wind. We have found that this factor alone more than offsets the cost "penalty" on IRR of moving to deeper and more remote locations. With this in mind, it is surprising that we, in our dataset find projects that deviate -81% from the mean capacity factor, and the fact that we find a negative trend in capacity factor (see Figure 8-13) despite that parks have moved further from shore, with higher CAPEX, in search of better conditions. This could partly be a result of new countries and investors entering with less knowledge about the importance of the wind resource. For example, the graph below shows the development in capacity factor over time for the studied countries.

Figure 5-1 Capacity factor per country over time, own data



It could however also be an indication that the best locations are already taken, thus forcing investors to invest in projects at inferior sites. Nevertheless, the capacity factor is a key driver, and should therefore be analyzed carefully. We recommend investors to use www.globalwindatlas.com for indicative analysis of potential locations. One of the strengths of this site is the applicability, easiness to use whilst still grasping all the complicated calculations of deciding the actual power and potential of the wind (i.e. taking account for the distribution of wind strength and direction, all based on tremendous amounts of historic data) and even making it possible to apply different turbine types. Afterwards, investors could have more extensive wind studies conducted at site to better grasp the wind quality and further develop the investment case.

Another key factor to produce a park are the energy loss factors. Our interview with Ørsted (Appendix A.1) indicated that this number is often as high as 15% especially due to cable loss that occur during energy transportation to the grid. This is an area of high potential as the cable loss is basically lost revenue, i.e., the wind resource has already been transformed into electricity and sold to the grid operators. The main trends here is to convert the power into high voltage and better coating of the cables. As parks move further away from shore this issue only becomes more relevant. Furthermore, the design of parks is constantly improved to better cope with the wake effect by taking the domination direction of the wind into account (Albadi M. , 2009). In our research it hasn't been a key driver for higher production, but nevertheless it deserves some attention, as it is a decision that cannot be changed when first the park is set up. Lastly, we found that efficient O&M in turn could drive production up due to less downtime, while also reducing OPEX. Here, as our interview with Ørsted confirmed, a trend in using machine learning to learn when to perform service at the optimal points in time (Appendix A.1).

5.1.1.2 Price of electricity

The price that investors get for the produced electricity is a combination of the market price and the support scheme in the respective country. As discussed in section 3.2.1.1, electricity prices are volatile, which imposes a great deal of uncertainty for investors, especially for intermittent RE sources such as wind energy. The intermittency effect is a great challenge to the entire energy infrastructure especially as intermittent energy sources possess a greater and greater proportion of the total energy consumption. The only way to effectively solve the problem is to create an economical feasible way of storing energy. This is a hot topic in research and could potentially lead to less volatile electricity prices (Albadi & El-Saadany, 2010). Another way to solve the intermittency problem is to have more interconnected energy supply systems. The idea is that if grids are connected across countries then countries with an over-supply of energy can sell to countries with a deficit. As such, an interconnected grid offers balancing through geographic spread which increases the security of supply. This is especially being investigated in the EU where grids are located within close proximity (Van Hertem & Ghandhari, 2010). The intermittency effect cannot be solved quickly, nor by any single investor. It is rather a societal challenge to support the transition from fossil fuels to electricity. Nevertheless the investor needs to understand how the problem effects the investment case.

As we become better at dealing with the intermittency effect and the non-storability of energy, the electricity prices are likely to become less volatile and random. Therefore, the investor will be able to forecast electricity prices with greater accuracy, which increases the credibility of the investment case and reduces the market risk. We recommend investors to use an Orstein-Uhlenbeck process for forecasting electricity prices. Also, we recommend investors to fully grasp the intermittency effect as it can have great impact on the price.

5.1.1.3 Support schemes

The other price driver is the support schemes. Albeit not a part of our financial analysis, this is, and has been an instrumental part of the attractiveness of the investment case. The support policies differ from country to country and are dynamic over time. Therefore, it is essential for the investor to understand the support schemes used in various countries and how they can be expected to change in the future. As stated in section 4.4, support schemes follow the RE goals and the industry development and therefore investors can undoubtedly expect less compensation from the local governments in the future. We have already seen this development in mature markets in Europe who has moved away from FiT support schemes to more market-based FiP schemes (Hiroux & Saugan, 2010) and it is backed by our calculations in section 4.3. As such, theory matches reality, but the central question is whether we can expect the same development in other less mature markets such as the Asian markets. We recommend investors to pursue investments in countries with FiT support schemes as they provide a high degree of revenue certainty.

5.1.2 Assessing the cost of offshore wind projects

This section will highlight the considerations investors should do regarding CAPEX, OPEX and decommissioning cost.

5.1.2.1 CAPEX

Recall section 3.2.2.2, where CAPEX was stated to constitute approximately 80% of total life time costs, incur within the first 3-4 years of the project lifetime ultimately resulting in a skewed cash flow structure for the investor. This high proportion of "upfront" cash outflows entails that most of the risk is found in the initial years. Despite the clear positive trend in diminish CAPEX/MW found in the literature, we urge investors to apply some levels of uncertainties when using the forecasted prices. This is due to the historical learnings, where we have found great differences in forecasted prices versus actual prices, indicating that investors should regard the various trajectories set forward by organizations promoting the wind industry as they might be positively biased. It might seem obvious that the forecasted prices differed from the actual, taking the uncertain nature of the future into account. However, we still think this is worth mentioning.

As shown in section 3.2.1.4, IRR is positively correlated with the nameplate capacity of the park, indicating economies of scale. In reality, both CAPEX and OPEX experience economies of scale but since they in our model are linear functions of project size, they don't show diminishing marginal costs. This is a shortcoming of our model, but the point is that investors should pay attention to economies of scale in costs. Therefore, we urge investors to regard the cost on a unit basis when assessing and comparing offshore projects.

Despite the economies of scale, a larger project results in higher total CAPEX costs, which in turn creates a higher risk and require more of the revenue to make the project valuable. We recommend investors to not blindly pursue economies of scale as risk also increases with park size.

We also find that the precise location of the project imposes great variations in CAPEX (recall Table 3-4 and our findings in section 3.3.5.1). We found that the relative improvement in capacity factor more than offsets the increased CAPEX. However we also found that investors in reality haven't accomplished higher capacity factors despite going further offshore. Therefore we recommend investors to conduct a thorough wind quality assessment to pick the optimal location.

Our recommendation, all else being equal, is that going further offshore (and increase costs) to get better wind conditions is worth it if you succeed in increasing capacity factor. Since governments ultimately control and determine where parks are established, developers are not free to locate parks where they wish and where they find optimal wind conditions. Therefore, we urge investors to work closely with governments, perhaps by proposing areas for the concessions or by providing industry insights to help governments make the most informed decisions on deciding where to locate new parks.

5.1.2.2 OPEX

In section 3.2.2.2.2 we analyzed the characteristics of OPEX for an offshore wind farm. Here we found, that there exist no variable costs, only a fixed cost, pr. MW, which is a unique proposition compared to other conventional energy sources like fuel or coal. As with CAPEX, we recommend viewing the cost on a per unit basis as there also exists some economies of scale. The importance of OPEX is clearly shown in section 3.3.5.1, where it is the primary driver of negative impact on IRR. O&M accounts for the majority of the OPEX cost (67%), recall Figure 3-15. Hence this is a key cost group. The nature of this cost group is not as fixed as CAPEX, and due to its continuity throughout the project lifetime, there is a potential in working on reducing this cost group. As stated in section 5.1.1.1, developers are especially looking into machine learning to better predict when to exchange parts in the turbine to avoid as much downtime as possible. Likewise, multiple investors have started using drones and robots to inspect and clean the blades e.g. [46]We recommend investors to follow the technological development and always use best-practice technologies to lower OPEX as much as possible.

5.2 The investment trade-off

Considering the above mentioned trends in the key drivers, we believe that investors faces a tradeoff between investing now or later. We believe that the investment timing dilemma is particularly interesting for the offshore wind industry being a high-tech, fast developing industry and because countries have entered the industry at different points in time, hence are at different stages of the lifecycle, recall Figure 3-19. This directly influence the project-specific value drivers as we have seen in chapter 3 and the support schemes as we have seen in chapter 4. Below, we list and discuss the major tradeoffs faced by an investor today.

[46] https://orsted.com/-/media/WWW/Docs/Corp/COM/Investor/CMD2018/CMD-Presentation-2018.pdf 03/05 13:47

The tradeoff can be summarized in the figure below:

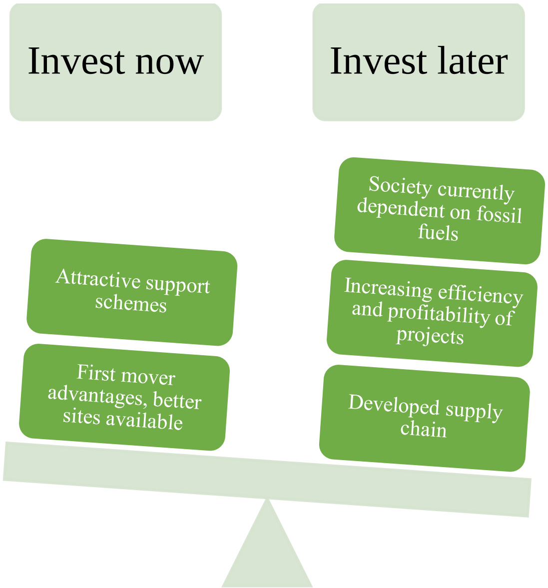


Figure 5-2 the investment timing dilemma

Our analysis in section 3 indicates that the literature projects major cost improvements in the future (see Figure 8-1 and Figure 8-2). Furthermore, our analysis shows that as parks have moved further form shore the wind quality measured by the capacity factor has not always followed suit, indicating that moving further from shore does not always improve revenue accordingly. A likely reason for this is that the best sites are taken first. Furthermore, in section 4.4, it was stated that support schemes follow the industry evolution and the RE goals of the country. This was backed by our calculations in section 4.3 and our findings of European markets moving away from FiT support schemes to more market-based FIP support schemes. As such, there seems to be a first-mover advantage in entering markets early as the likelihood of getting attractive sites and obtaining long-term attractive support schemes are higher. This first-mover advantage does however come with an added risk.

First off mature markets are more likely to have well developed supply chains, resulting in lower costs and development risks.

Another argument for postponing the investment is the society's current reliance on fossil fuels and hence a need for investments in initiatives that supports a transition towards an electricity driven society. This will in turn also help diminish the intermittency challenge. Furthermore, in section 5.1.1 and 5.1.2 we identify multiple trends that could significantly reduce costs and increase revenue in the future. In this regard, it could be attractive for an investor to postpone the investment and "free-ride" on the knowledge developed by others regarding turbine efficiency, machine learning in O&M etc. As such, the imitator could appropriate more value than the innovator (Teece, 1986).

Our research shows that a lot of work is being put into tackling the energy loss factors, the intermittency effect etc., which could make it attractive to postpone until technological development allows investors to better handle this issues.
Essentially, the choice comes down to whether to invest now and reap the first-mover advantage of attractive support schemes and project sites or to wait for the industry to develop thus benefitting from more developed supply chain and the diffusion of global knowledge and innovation to build more cost efficient parks.

5.3 Potential weaknesses and threats to the offshore wind industry

Despite the positive outlook for offshore wind energy, we find it crucial to discuss some factors that could hamper the development.

First we find, that the current and projected success of the industry is built on the expected continuous investments, which will drive the costs down. However, as highlighted above, this could get investors to postpone their investments resulting in a decreasing trajectory and hence hamper the development and attractiveness of the offshore industry.
Second, we see a threat of the society not being ready to be driven by electricity. The logic here is, that electricity cannot be stored, why imposes a great challenge for the offshore wind industry and other intermittent energy sources. Therefore, a need for investments and new technologies in storing electricity and /or using the power wisely, e.g. with smart homes that heat up during periods of low demand is needed.
Third, there is the natural risk of a new groundbreaking technology emerging, which could make investments in offshore decrease, and as in the first threat, hamper the development of offshore even more as the future is reliant on continuous investments.
The authors acknowledge the society's current reliability on fossil fuels like coal and gas is likely to continue for the coming decades. However, even as offshore wind energy only makes up 0,8% of the total electricity demand and despite the youth of the industry and its inherent challenges it has already made a fundamental shift in the potential usage of electricity as the main energy source, which is seen in e.g. the strong policies trying to promote offshore wind energy. With the potential of offshore wind energy and its increasing competitiveness the winds seem to blow in favor of the offshore wind energy.

6 Conclusion and future research

6.1 Conclusion to our research

The purpose of this thesis has been to analyze how investors should assess offshore wind projects to achieve the best returns. In this regard, we first sat out to research which drivers are most important for the financial returns and what that can be learned from their historical development. This was followed up by an analysis of how support schemes influences offshore wind projects.

To answer the research question,

How should investors assess offshore wind projects to achieve the best returns?

a comprehensive assessment of the key drivers was conducted for 449 real-life projects across 16 countries (on 3 continents) and 20 years. This global scope allowed us to identify meaningful, global performance trends. In this regard, we can conclude that the industry performance has developed like an S-curve in different "waves" and the profitability has improved over time, but with great geographical variances.

For the key value drivers, we can conclude that the most important drivers are respectively: Nameplate Capacity (+), OPEX (-), Capacity Factor (+), distance to shore (-) and depth (-), meaning that the investors should pay greatest attention to these. Albeit, we cannot observe the influence that electricity prices (+), CAPEX (-), decommissioning costs (-) and energy loss factors (-) have on IRR through the regression model, we have tested them separately against IRR. Electricity price has shown to have the biggest influence on IRR, followed by CAPEX and lastly the energy loss factor. Furthermore, based on the risk/return features of the support schemes, we consider the FiT tariff to be most attractive due to the safety it provides to investors.

In conclusion, we can say that investors should asses offshore wind projects by combining the knowledge of all the identified key value drivers with the knowledge of the different industry lifecycle stages to enter markets at the optimal point in time and invest in projects with most attractive characteristics according to our key value drivers. To do so, investors should also focus on the support schemes and the inherent trade-off between investing now in a less mature industry with a higher risk and potential return or postponing to invest in a more mature and thus safer market. By doing so, we believe the investor is in the optimal position to achieve the best returns.

6.2 Perspectives, limitations, and suggestions to further research

Having concluded on the findings, we wish to pay some attention to other perspectives not within our scope that we find interesting for further research.

Our "high level" perspective has several advantages, like being able to compare returns on a broad, global scale. However, we undoubtedly miss some details because of this scope. If we have had a case specific perspective, we would have had the ability to go into extensive details with the revenue, costs, subsidies, capital structure, tax etc., which would have given us a more precise IRR. However, as stated in 1.7.3, the purpose of our thesis is not to add to the literature on how a proper valuation of offshore wind parks should be conducted and therefore, given our scope, it would not make sense to create a detailed cash flow of the projects.

Also, we have chosen to use IRR as our measure for return, despite for its shortcomings. We decided not to focus on e.g. forecasting techniques, stochastic simulation models like the real options or other valuation methods, as these would not allow us to compare returns through time and across countries, due to the inherent complexity of both building and interpreting these models. We argue, that a more in-depth valuation method could be beneficial after an investor has made the initial high-level analysis to determine possible projects. An investor could potentially use our thesis to identify the right locations and then use another thesis or framework for a more in-depth valuation.

Another consequence of our global scope is the obvious lack of attention devoted to each geographical area and country. We have focused on a few countries on a rather high level and the geographical differences could be given more attention. This is an ideal focus for new research; investors who have used our methodology to determine where to invest on a high level should afterwards gather detailed geographical information to complete the understanding of the differences.

Some areas of this thesis have received little attention. Initially we set up some delimitations to maintain our scope. However, as we also note, some of our delimitations are interesting areas for investors to understand especially regarding project risk and cost of capital. As such, a natural extension of this thesis could also be to include project risk and cost of capital in order to fully understand the attractiveness of the projects in our dataset. Likewise it could be interesting to further explore the investors incitements for investing in projects like offshore wind projects. Throughout our thesis we have assumed that the investor is profit maximizing, which could be interesting to further research, as there could be other potential incitements driving the investment.

Another area where we haven't paid too much attention, is the electricity price. Here we argued for the intermittency effect has great impact on the actual electricity price, which our model only incorporates as a simple deduction in the average electricity price. Here a model that accounts for supply and demand, incorporating the effect of wind volatility, and the effect it has on price could improve the accuracy of our valuations.

Ultimately, we believe that offshore wind possesses great potential and on its continuous development it could change the economics of the energy market. Albeit, there exist some challenges to be solved for wind to be utilized and trusted as a main energy resource, the prospects of offshore wind energy seem positive, as the industry seems to have a tailwind.

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8 Appendix

The audio files for A.1 and A.2 can be provided upon request.

A.1 Meeting with Nicholas Birkholm of Ørsted A/S

<u>Date</u>	Wednesday, April 17th 09:00-10:30
<u>Location</u>	Ørsted HQ, Gentofte
<u>Attendees</u> <u>(position and role)</u>	Nicholas Birkholm (Financial Analyst, Asset Valuation) Mathias Reimich (author, interviewer) Valdemar Stage (author, interviewer)
<u>Agenda</u>:	To get insights into how Ørsted, a company specialized in renewable energy and focusing on offshore wind energy, creates their investments cases. Hereunder their key value drivers. Testing our model and getting feedback.
<u>Pre-assigned questions:</u>	Yes. Semi-structured interview technique. Questions follow in A.1.1
<u>Materials provided:</u>	No tangible material was provided.
<u>Transcript of interview:</u>	No but notes were taken down.

Resumé and key takeaways:

The interview was focusing on how Ørsted build their investments cases. As Ørsted is a developer, this interview had more focus on the entire investment case, i.e.. the development phase and construction phase as well as the operational phase.

We tested our findings of key value drivers which was confirmed to be important to regard.

We tested our model with the response that figures “wasn’t out of the ball park” (both in terms of CAPEX, OPEX, Electricity prices and Capacity factors, and also our IRR’s).

However it was highlighted that subsidies and taxes plays an important role. We were urged to look at the geographical differences.

Likewise we were made aware that our simplicity of electricity prices has several limitations, not accounting for base-load and wind-cap prices (the intermittency effect).

We were confirmed in using a decrease in productivity each year of 0,5%.

We were made aware that we should implement an energy loss factor of 15%.

We were confirmed in our choice of valuation method (IRR) is widely used and the real options method is not used in Ørsted to do investment cases.

A.1.1 Questions to A.1

- Hvilke Value Drivers kigger i på når i skal estimere Revenue?
- Hvordan forecaster i elpriserne?
  - Model? Tidshorisont?
- Er det nødvendigt for jer at forecaste elpriser hvis der er en Power-Purchase Agreement der giver en fixed pris?
- Tager i højde for at turbinerne falder i effektivitet i jeres beregninger? I givet fald, hvordan?
- Antager i at møllerne bliver operational gradvist eller på samme tid?
- Hvilken faktorer har en indflydelse på hvor omkostningsfuldt det er at opføre en park?
- Indregner i economies of scale i jeres OPEX? I givet fald, hvordan?
- Hvad er jeres forventninger til de fremtidige omkostninger?
- Hvilken valuation model bruger i?
- Hvor vigtige er subsidierne for værdiansættelsen og har dette ændret sig over tid?
  - Forventer du at subsidier vil have en mindre indflydelse på investment casen i fremtiden?
- Er der nogle lande-specifikke faktorer der gør det mere/mindre attraktivt at investere i forskellige lande?
- Hvilken levetid anvender i for parkerne?
- Medregner i en decommission cost og i givet fald, hvordan sættes den?
  - Når man ser det på projekt basis så giver det mening at man vil se

A.2 Meeting with Peter Staudt of PensionDanmark

Date	Wednesday, March 13th
	10:00-11:00
Location	PensionDanmark HQ, Copenhagen
Attendees	Peter Staudt (Financial Analyst, Asset Valuation)
(position and role)	Mathias Reimich (author, interviewer)
	Valdemar Stage (author, interviewer)
Agenda:	To get insights into how PensionDanmark, an institutional investor, regards and builds investments cases in offshore wind energy, Hereunder their key value drivers. Testing our assumptions and getting feedback.
Pre-assigned questions:	Yes. Semi-structured interview technique. Questions follow in A.2.1
Materials provided:	No tangible material was provided.
Transcript of interview:	No but notes were taken down.

Resumé and key takeaways:

The focus of the interview was how PensionDanmark establishes their investment case. As an institutional investor, PensionDanmark only invests in projects when they are in the operational phase and therefore they are not involved in the entire investment case.

We went through our key value driver and we were confirmed in their importance.

We talked about what influences cost and revenue, which helped us establish what to look for in chapter 3.

We were told that support schemes vary from park to park, but are generally the same within countries.

We were told that cost differences exists due to more/less developed supply chains and infrastructure.

We were confirmed in our method of calculation Revenue from the Capacity Factor

We were confirmed in our choice of valuation method (IRR) and were told that Real Options are not used in practice (at least to their knowledge)

A.2.1 Questions to A.2

Interview med Peter Staudt

Vi vil gerne undersøge:

Hvordan kan nationalstater skabe det bedste investor miljø for at fremme investeringer i offshore vindenergi?

For at belyse ovenstående vil vi beregne og sammenligne IRR for vindprojekter uden subsidier, på tværs af (endnu ikke valgte) lande. Dette vil vi bruge til at indikere, hvilket land der har haft den bedste learning curve. Vi vil derefter foretage en komparativ analyse, hvor vi sammenligner landenes CAGR på IRR. Hvor har der været mest profitabelt at investere? Dette vil vi forsøge at forklare ud fra lande specifikke faktorer såsom Subsider, vind, Grid connectivity, politisk stemning, strøm pris (Hvis du har andre faktorer er vi åbne for foreslag). Dette vil udmunde i en analyse af, hvad landene kan lære af hinanden og hvad best practice bør være.

Spørgsmål:

1) Scope: Er det for bredt at have både on og offshore? Timeframe er fra 2000 til nu.
2) Scope: Giver en afgrænsing ift. parkernes nominelle power (størrelse)>30 MW?
3) Hvordan beregner I revenue for parkerne?
   a. Vi vil gøre følgende:
      i. Avg. Windspeed*Capacity factor*Nominel power*(24 timer*365)
      ii. Vi har fundet wind og capacity factor på: https://globalwindatlas.info/
      iii. Vi er i tvivl om hvordan man finder capacity factor og hvordan det skal forstås
4) Hvordan beregner i afkastkravet?
   a. CAPM + Kapitalstruktur for Peers, men vi tænker at tillægge et projektspecifikt premium der aftager over tid. Ville det give mening?
      i. Pointen er at vise at risici er blevet mindre som branchen er modnet
5) Omkostninger
   a. Vi anvender litterature såsom IRENA, 2018 til at udlede Cost/MW
      i. CAPEX, OPEX
   b. Er der mange nationale forskelle på omkostninger?
   c. Skal vi tage R&D med?
6) Værdiansættelsesmetode
   a. Vi vil anvende en NPV/IRR, hvad gør i?
   b. Vi har både projekter der er operationelle og nogle der er under konstruktion. Bør de værdiansættes på samme måde? (kan vi antage at alle bliver operationelle?)
7) Subsidier på makroniveau (findes der sammenligninger?)

A.3 Meeting with Jake Badger of DTU Wind

Date	Wednesday, March 18th
	15:00-16:15
Location	Teleconfernece (CBS)
Attendees	Jake Badger, Head of Section “Wind Resource Assessment Modelling” at DTU Wind Energy
(position and role)	Mathias Reimich (author, interviewer)
	Valdemar Stage (author, interviewer)
Agenda:	To get insights into how the www.globalwindatlas.com works and how it can be used. Insights into the behind laying calculations.
Pre-assigned questions:	No. Not structured interview technique.
Materials provided:	No tangible material was provided.
Transcript of interview:	No but notes were taken down.

Resumé and key takeaways:

It was confirmed that our logic of multiplying the capacity factor with the capacity of the given farm is the intended idea of the site.

We got key insights into the advanced calculation behind the numbers on the page. It was confirmed that the site in fact accounts for the characteristics of the wind, e.g. that it is distributed as a Weibull-distribution (that is, that it has different strength), it comes from different directions, turbine height placement (100m) effects on the wind power, the temperature of the site, which also affects the energy in the wind hence affecting the power output.

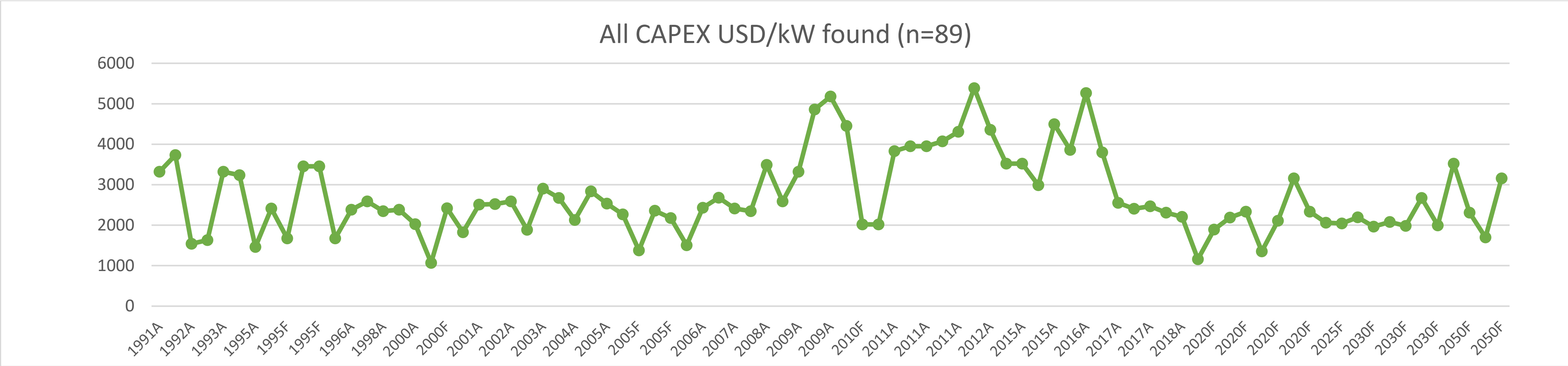


Figure 8-1 CAPEX development through time.

Triangulated data based on BVG Associates (2019), BVG Associates (2017), BVG Associates (2012), BVG Associates (2011), DEA (2018), Prässler and Schaechtele (2012), IEA (2017), Greenacre and Hepstonstall (2012), Andersen and Fuglsang (1996). Costs adjusted for inflation and converted to 2019 USD/kW. (n=80).

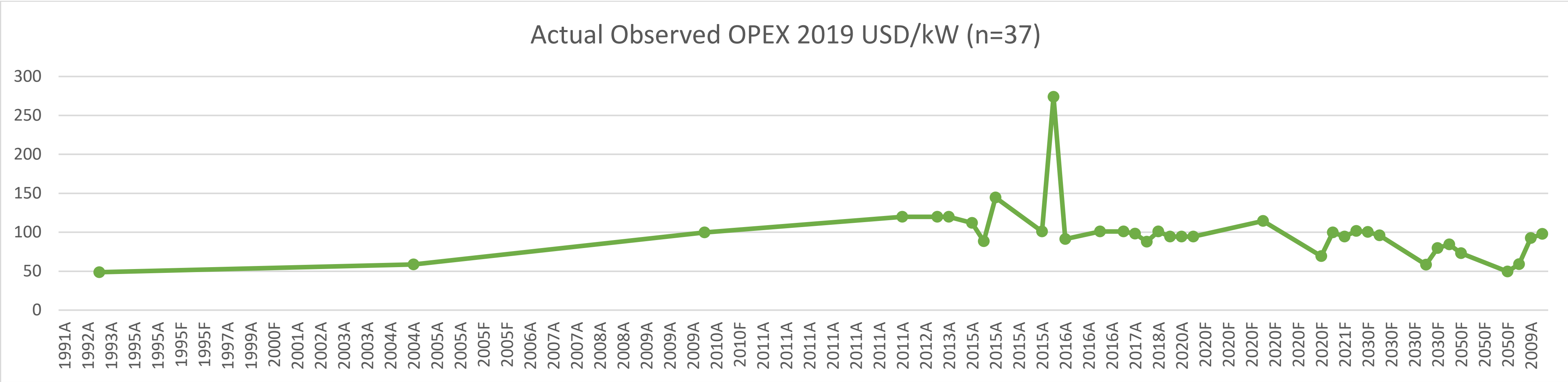


Figure 8-2 OPEX development through time.

Triangulated data based on BVG Associates (2019, 2017, 2012, 2011), DEA (2018), IEA (2017), Greenacre and Hepstonstall (2012), Andersen and Fuglsang (1996). Costs adjusted for inflation and converted to 2019 USD/kW (n=37).

Table 8-1 Multiple Linear Regression Analysis. Own creation in R from own data base

```
Call:
lm(formula = IRR ~ OPEX + Depth + Distance_to_Shore + Capacity +
    Capacity_factor + Estonia + China + Canada + Denmark + USA +
    France + Germany + Greece + Ireland + Japan + Poland + Sweden +
    Taiwan + South_Korea + United_Kingdom + Netherlands, data = Data_multiple_linear)

Residuals:
      Min        1Q    Median        3Q       Max
-0.139020 -0.012262  0.002458  0.015083  0.069636

Coefficients: (1 not defined because of singularities)
                    Estimate Std. Error t value Pr(>|t|)
(Intercept)       -2.348e-01  1.215e-02 -19.331  < 2e-16 ***
OPEX              -5.698e-04  4.041e-05 -14.102  < 2e-16 ***
Depth             -4.871e-04  1.242e-04  -3.923 0.000102 ***
Distance_to_Shore -2.980e-04  6.133e-05  -4.859 1.65e-06 ***
Capacity           1.073e-06  7.531e-08  14.245  < 2e-16 ***
Capacity_factor    4.562e-01  1.857e-02  24.564  < 2e-16 ***
Estonia            1.358e-02  1.253e-02   1.084 0.279151
China              9.949e-02  7.850e-03  12.674  < 2e-16 ***
Canada            -8.365e-02  1.018e-02  -8.220 2.45e-15 ***
Denmark            4.243e-02  9.590e-03   4.425 1.23e-05 ***
USA               -1.331e-01  9.474e-03 -14.052  < 2e-16 ***
France             3.252e-02  1.023e-02   3.179 0.001586 **
Germany           -8.151e-02  8.382e-03  -9.724  < 2e-16 ***
Greece             5.362e-02  8.953e-03   5.989 4.47e-09 ***
Ireland            4.499e-02  1.106e-02   4.069 5.62e-05 ***
Japan              1.747e-01  9.308e-03  18.766  < 2e-16 ***
Poland             4.802e-02  9.948e-03   4.827 1.93e-06 ***
Sweden             6.109e-03  9.763e-03   0.626 0.531829
Taiwan             1.258e-01  9.076e-03  13.866  < 2e-16 ***
South_Korea        2.577e-02  1.011e-02   2.550 0.011111 *
United_Kingdom     4.547e-02  7.706e-03   5.900 7.40e-09 ***
Netherlands               NA         NA      NA       NA
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.02508 on 428 degrees of freedom
  (10 observations deleted due to missingness)
Multiple R-squared:  0.8839,    Adjusted R-squared:  0.8785
F-statistic:   163 on 20 and 428 DF,  p-value: < 2.2e-16
```

Table 8-2 Coefficients adjusted for Scale

	Coefficient	Standard Deviation	Adjusted for scale
OPEX	-5,70E-04	785,4561	-44,8%
Depth	-4,87E-04	13,5765	-0,7%
Distance	-2,98E-04	30,72084	-0,9%
Capacity	1,07E-06	423228,7	45,4%
Capacity_factor	4,56E-01	0,106628	4,9%

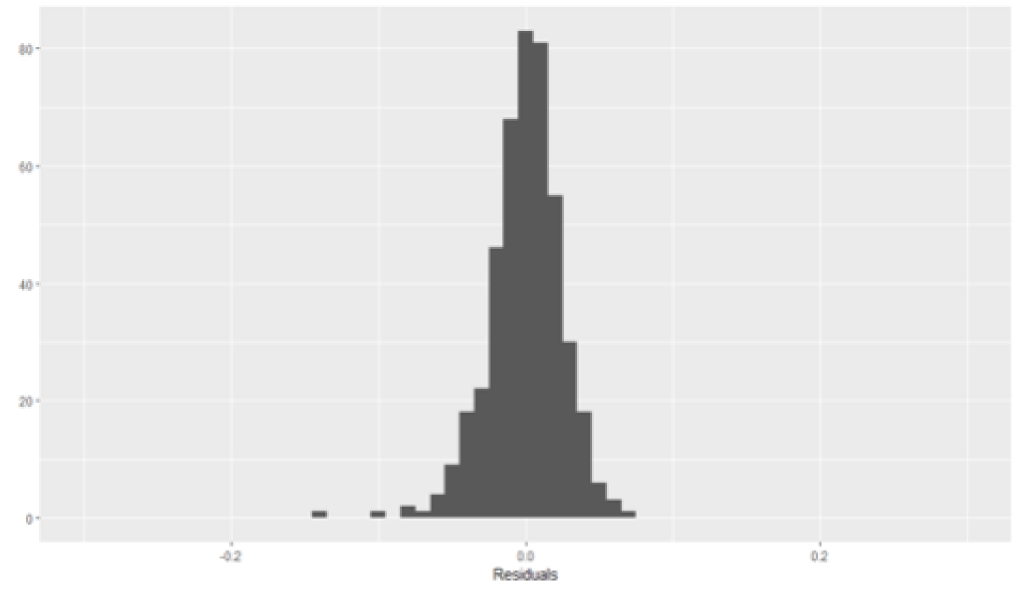
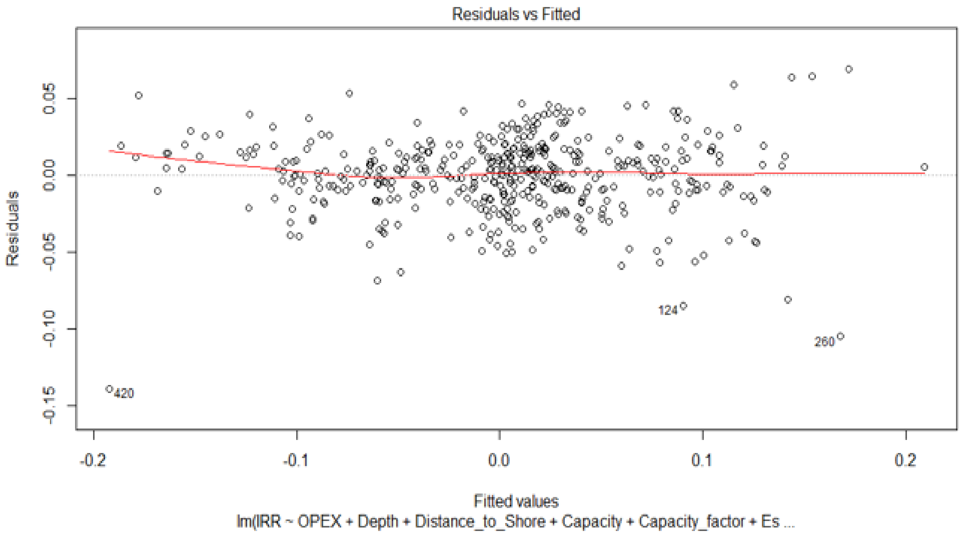


Figure 8-3 Histogram of residuals. Own creation in R from own data base

Figure 8-4 the normal distribution of the observations. Computed in R with own data



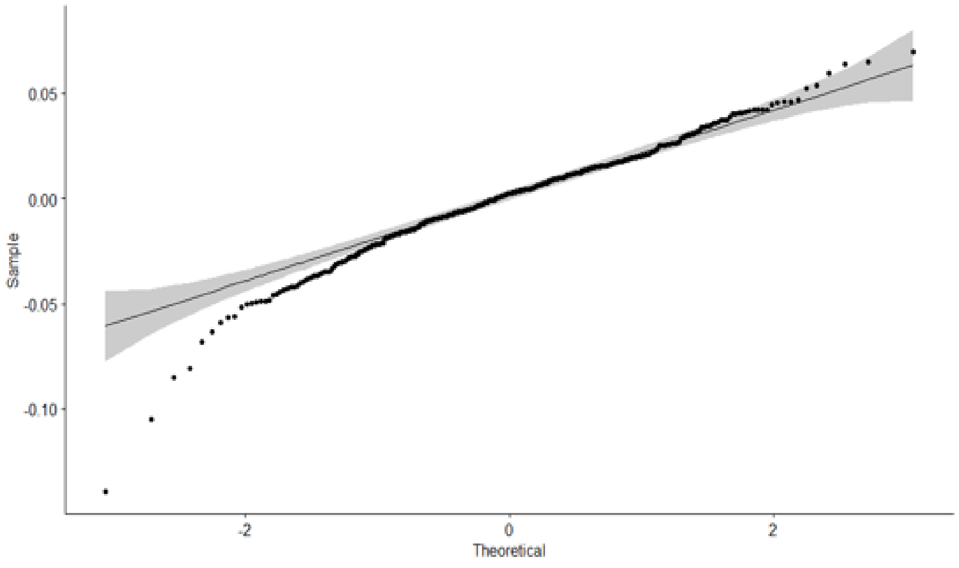


Figure 8-5 Q-Q the relationship between IRR and the variables. Computed in R with own data

Figure 8-6 Standardized residuals. Computed in R with own data

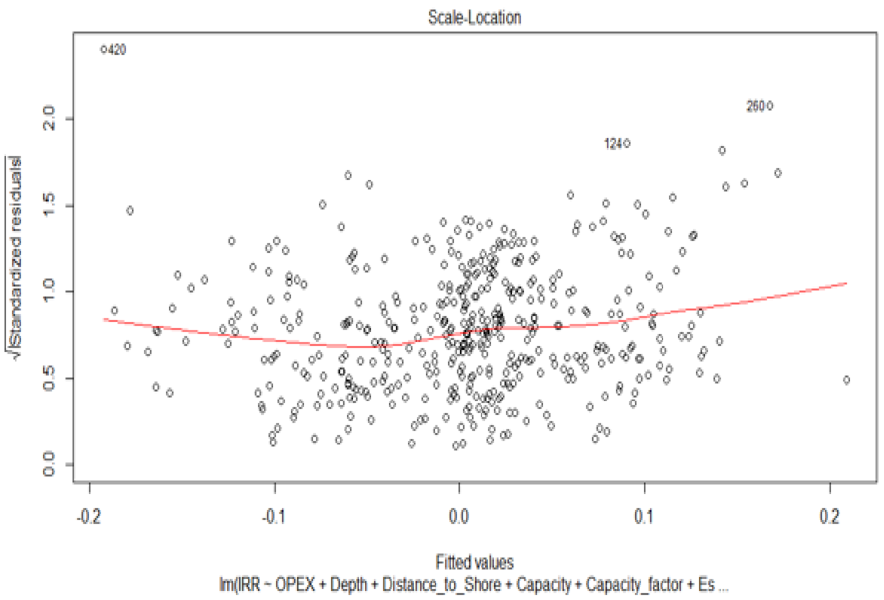


Table 8-3 10 projects will never achieve an NPV=0

Hence the IRR is impossible to calculate. We remove these projects from our multiple linear regression

Count	Wind farm Name	Capacity	Capacity Factor	Project start	CAPEX	PnL	20
Brazil	Asa Branca 1 - CEMAB 1	400.000	36%	2019	1,0	IRR	
Brazil	Asa Branca 2 - CEMAB 2	400.000	42%	2018	1,0	IRR	
Brazil	Asa Branca 3 - CEMAB 3	400.000	42%	2017	1,1	IRR	
Brazil	Asa Branca 4 - CEMAB 4	10.390.000	42%	2015	1,0	IRR	
China	CNOOC Weihai - Phase I	102.000	10%	2017	1,0	IRR	
USA	Galveston Offshore Wind Phase 1	150.000	32%	2017	1,1	IRR	
USA	Icebreaker	20.700	40%	2016	1,1	IRR	
China	Tianjin Hangu	200.000	8%	2014	1,0	IRR	
USA	Vermilion Bay	36.000	26%	2019	1,0	IRR	
USA	Virginia - Dominion 2	1.500.000	44%	2015	1,4	IRR	

Table 8-4 Regression output, 09-15

```
Call:
lm(formula = IRR ~ OPEX + Depth + Distance_to_Shore + Capacity +
    Capacity_factor + Estonia + China + Canada + Denmark + USA +
    France + Germany + Greece + Ireland + Japan + Poland + Sweden +
    Taiwan + South_Korea + United_Kingdom + Netherlands, data = Data_year_2009t2015)

Residuals:
      Min        1Q    Median        3Q       Max
-0.050172 -0.009911 -0.001188  0.012428  0.034872

Coefficients: (3 not defined because of singularities)
                    Estimate Std. Error t value Pr(>|t|)
(Intercept)       -2.443e-01  1.378e-02 -17.735  < 2e-16 ***
OPEX              -4.641e-04  8.829e-05  -5.257 6.32e-07 ***
Depth             -4.732e-04  2.141e-04  -2.210 0.028980 *
Distance_to_Shore -2.169e-04  7.474e-05  -2.901 0.004408 **
Capacity           9.129e-07  1.699e-07   5.372 3.79e-07 ***
Capacity_factor    3.728e-01  1.932e-02  19.290  < 2e-16 ***
Estonia            2.361e-02  1.993e-02   1.185 0.238422
China              1.095e-01  9.525e-03  11.495  < 2e-16 ***
Canada                    NA         NA      NA       NA
Denmark            4.428e-02  1.526e-02   2.902 0.004404 **
USA               -8.724e-02  1.348e-02  -6.471 2.13e-09 ***
France                    NA         NA      NA       NA
Germany           -4.479e-02  1.023e-02  -4.378 2.54e-05 ***
Greece             6.301e-02  1.413e-02   4.459 1.85e-05 ***
Ireland            5.948e-02  1.965e-02   3.027 0.003017 **
Japan              1.495e-01  1.561e-02   9.578  < 2e-16 ***
Poland             6.083e-02  1.624e-02   3.747 0.000275 ***
Sweden             1.163e-02  1.401e-02   0.830 0.408255
Taiwan             1.187e-01  1.303e-02   9.108 2.02e-15 ***
South_Korea        2.505e-02  1.401e-02   1.788 0.076229 .
United_Kingdom     6.447e-02  9.522e-03   6.771 4.79e-10 ***
Netherlands               NA         NA      NA       NA
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.01729 on 122 degrees of freedom
Multiple R-squared:  0.9253,    Adjusted R-squared:  0.9143
F-statistic: 83.94 on 18 and 122 DF,  p-value: < 2.2e-16
```

Table 8-5 Regression output 16-19

```
Call:
lm(formula = IRR ~ OPEX + Depth + Distance_to_Shore + Capacity +
    Capacity_factor + Estonia + China + Canada + Denmark + USA +
    France + Germany + Greece + Ireland + Japan + Poland + Sweden +
    Taiwan + South_Korea + United_Kingdom + Netherlands, data = Data_year_2016t2019)

Residuals:
      Min        1Q    Median        3Q       Max
-0.137087 -0.006523  0.000653  0.007212  0.035271

Coefficients: (1 not defined because of singularities)
                    Estimate Std. Error t value Pr(>|t|)
(Intercept)       -2.457e-01  9.859e-03 -24.925  < 2e-16 ***
OPEX              -2.471e-04  5.226e-05  -4.729 3.79e-06 ***
Depth             -4.873e-04  8.689e-05  -5.608 5.43e-08 ***
Distance_to_Shore -4.564e-04  4.768e-05  -9.572  < 2e-16 ***
Capacity           4.629e-07  9.722e-08   4.762 3.26e-06 ***
Capacity_factor    4.728e-01  1.527e-02  30.958  < 2e-16 ***
Estonia            4.642e-03  8.692e-03   0.534  0.59380
China              1.083e-01  6.371e-03  17.001  < 2e-16 ***
Canada            -8.532e-02  7.061e-03 -12.084  < 2e-16 ***
Denmark            2.441e-02  7.488e-03   3.260  0.00127 **
USA               -1.236e-01  7.005e-03 -17.638  < 2e-16 ***
France             1.867e-02  7.160e-03   2.607  0.00969 **
Germany           -8.853e-02  6.939e-03 -12.759  < 2e-16 ***
Greece             4.291e-02  6.836e-03   6.277 1.52e-09 ***
Ireland            2.342e-02  7.694e-03   3.044  0.00258 **
Japan              1.520e-01  7.016e-03  21.668  < 2e-16 ***
Poland             4.419e-02  7.228e-03   6.114 3.74e-09 ***
Sweden            -2.056e-04  8.217e-03  -0.025  0.98006
Taiwan             1.124e-01  6.782e-03  16.575  < 2e-16 ***
South_Korea        2.206e-02  7.549e-03   2.922  0.00380 **
United_Kingdom     4.254e-02  6.510e-03   6.535 3.56e-10 ***
Netherlands               NA         NA      NA       NA
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.01467 on 249 degrees of freedom
Multiple R-squared:  0.9594,    Adjusted R-squared:  0.9561
F-statistic:   294 on 20 and 249 DF,  p-value: < 2.2e-16
```

Figure 8-7 Q-Q Plot for 09-15 data

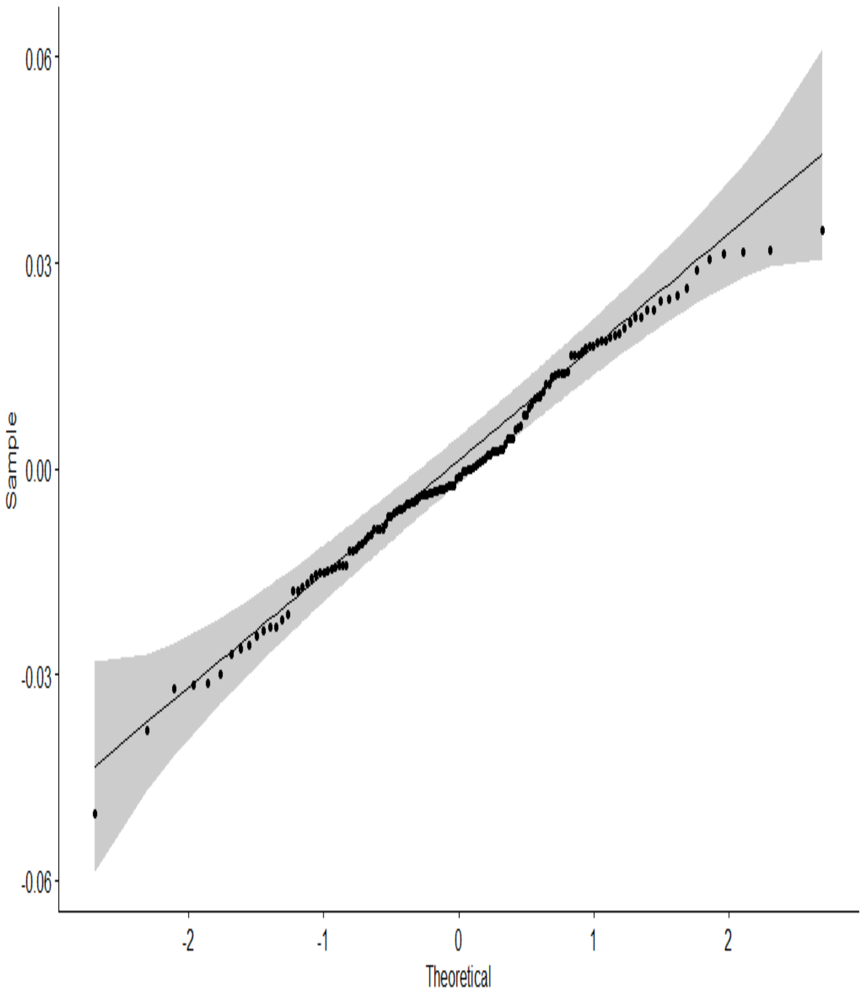
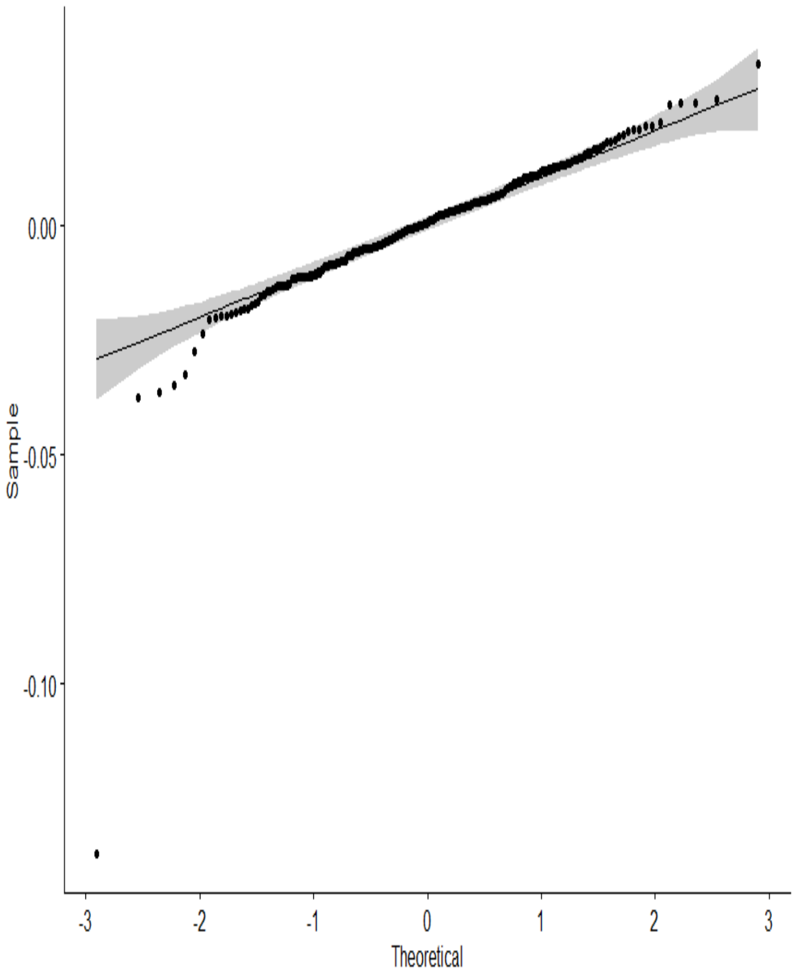


Figure 8-8 Q-Q Plot for 16-19 data



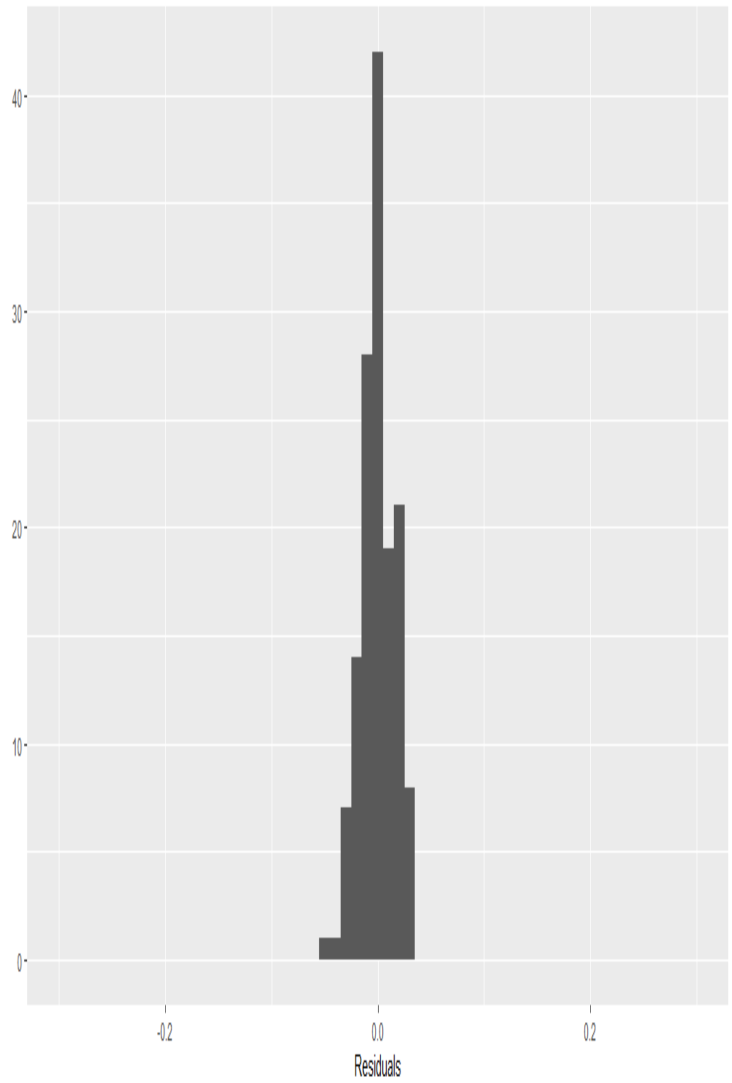
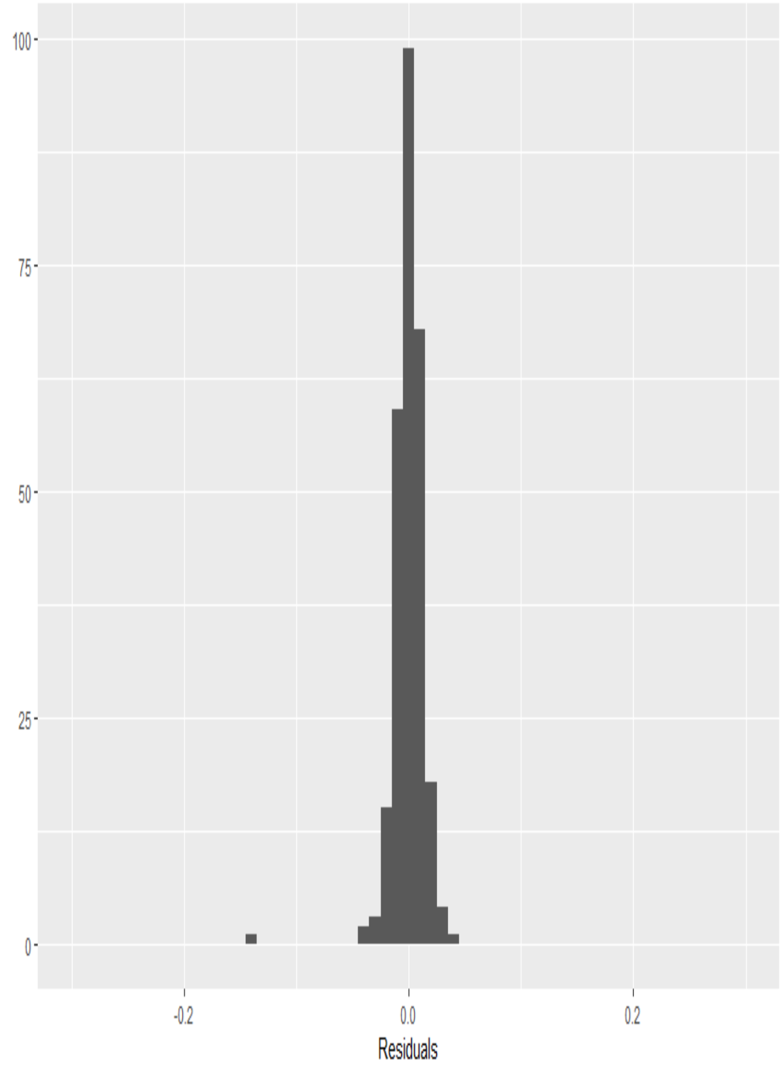


Figure 8-9 Histogram 09-15 data

Figure 8-10 Histogram 16-19 data



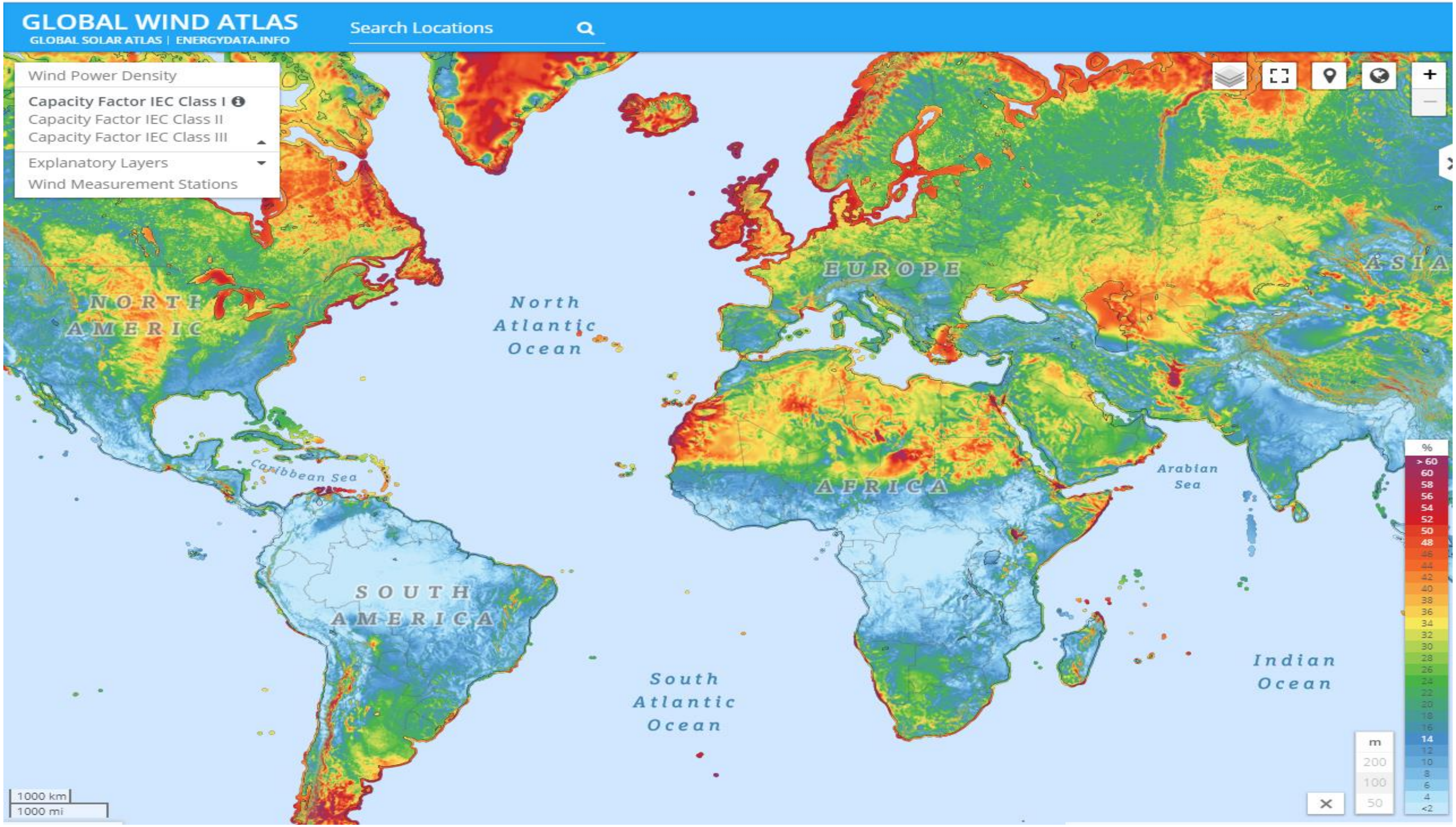


Figure 8-11 Wind Distribution based on Global Wind Atlas

```python
# -*- coding: utf-8 -*-
import scrapy


class TheWindpowerSpider(scrapy.Spider):
    name = 'thewindpower'
    allowed_domains = ['www.thewindpower.net']
    start_urls = ['https://www.thewindpower.net/windfarms_list_en.php']
    urllist = None

    def start_requests(self):
        if self.urllist:
            with open(self.urllist, encoding='utf-8') as f:
                for url in f:
                    yield scrapy.Request(url.rstrip(), self.parse_details)
        else:
            super().start_requests()

    def parse(self, response):
        form = response.css('#id_form')
        for option in form.css('option')[1:]:
            country_code = option.css('::attr(value)').get()
            # country = option.css('::attr(label)').get()
            # yield {country_code: country}
            yield scrapy.FormRequest.from_response(
                response,
                formdata={'pays': country_code},
                callback=self.parse_country,
            )

    def parse_country(self, response):
        country = response.css('h2::text').get()
        table = response.css('h2 ~ table')
        for row in table.css('tr:not([class])'):
            i = {}
            i['country'] = country
            i['name'] = row.xpath('./td[1]/a/text()').get()
            # TODO? (dismantled), etc. in the name
            i['url'] = response.urljoin(row.xpath('./td[1]/a/@href').get())
            i['power'] = row.xpath('./td[2]/text()').get()
            i['turbines'] = row.xpath('./td[3]/text()').get()
```

.\windfarms\spiders\thewindpower.py (1,1) python unix   Alt-g: show bindings, CtrlG: open help

Figure 8-12 Webscrape code of "thewindpower.net"

Figure 8-13 Worldwide Capacity factor over time

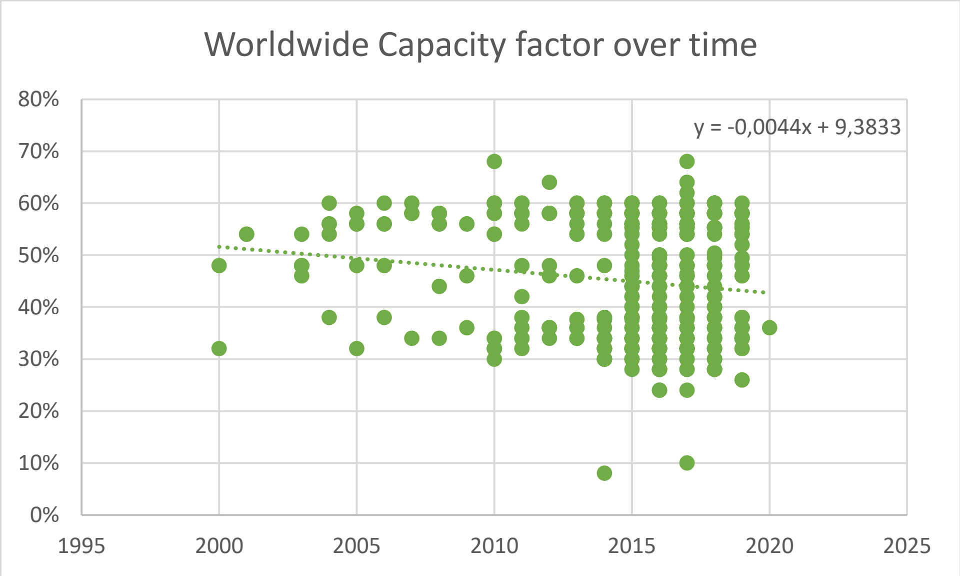


Table 8-6 IRR with subsidies vs IRR without.

Sources: https://www.ceer.eu/documents/104400/-/-/41df1bfe-d740-1835-9630-4e4cccaf8173, https://www.ceer.eu/documents/104400/-/-/8b86f561-fa0b-0908-4a57-436bffceeb30, https://qvartz.com/media/2052/offshorewind_china.pdf, https://www.carbontrust.com/news/2014/09/china-offshore-wind/ . SeeTable 8-7 for actual observations.

IRR_with subsidies	**China**	**Germany**	**Denmark**	**Netherlands**	**Ireland**	**Average**		Average of IRR_No_subs	China	Germany	Denmark	Netherlands	Ireland	Average
2012	0%	6,16%				6,2%		2012	-0,6%	-10,4%				-4,9%
2013	4,0%	0,00%		0,3%		3,5%		2013	0,7%	-9,6%		-8,7%		-3,3%
2014	2,4%	0,00%	7,0%			2,6%		2014	-0,5%		0,1%			-0,4%
2015	6,7%	14,76%	12,3%			7,5%		2015	3,3%	-11,3%	2,2%	-2,3%	2,6%	2,0%
2016	7,5%	0,00%	9,5%			7,6%		2016	3,9%	-10,4%	3,1%			2,3%
2017	16%	0,00%	11,7%	8,8%	13,6%	14,3%		2017	7,2%	-8,2%	5,3%	0,5%	7,7%	4,1%
Average	7,5%	9,03%	10,5%	6,7%	13,6%	7,9%		**Average**	**3,0%**	**-9,6%**	**3,5%**	**-1,9%**	**6,7%**	**1,3%**

Table 8-7 Observed subsidy prices. Same sources as table 10-7.

USD/kWh	Years					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**
China		**0,109**	**0,105**	**0,105**	**0,105**	**0,119**
FIT		0,109	0,105	0,105	0,105	0,119
Denmark	**0,046**	**0,069**	**0,091**	**0,101**	**0,081**	**0,077**
FIT	0,046	0,069	0,091	0,101	0,081	0,077
Germany	**0,135**	**0,163**	**0,171**	**0,149**	**0,193**	**0,188**
FIT	0,159	0,163	0,171	0,186	0,193	0,188
FIP	0,135		0,182	0,149		
Ireland					**0,129**	**0,078**
FIT					0,129	0,078
Netherlands	**0,122**	**0,120**	**0,000**	**0,000**	**0,129**	**0,078**
FIT	0,122	0,120	0,000	0,000	0,129	0,078

Table 8-8 Weighted Average IRR over time and pr. country

Average of IRR in %	Project start																			
Country	**2000**	**2001**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**
Canada																-11,71	-7,02	-8,68	-5,47		-9,15
China					-2,50	-0,51	-3,92	-4,37	-3,28	-3,09	-2,83	-0,61	0,69	-0,48	3,28	3,85	7,58	8,11	6,41	6,68	2,74
Denmark				4,39	2,48		-1,69							0,12	2,19	3,14	5,28	6,13	7,69		4,01
Estonia															-4,14	-1,75	0,77	0,81	0,89		-0,44
France																-2,53	-1,63	2,17	5,33		-0,33
Germany					-9,17	-8,28		-12,58	-10,03	-11,50	-11,61	-10,36	-9,59		-11,31	-10,42	-8,23	-7,50	-7,24		-9,77
Greece															-6,93	-5,62	-1,44	-2,32	2,64		-3,19
Ireland															2,58		7,68	8,21	9,01		7,53
Japan	2,85										0,53				10,64	10,61	10,12	12,64	11,40		10,02
Netherlands		-0,54	-1,17							-6,42	-10,95		-8,71		-2,28		0,48	1,41	2,27		-1,64
Poland															-0,33	0,28	2,84	3,37	0,44		1,45
South Korea													-12,88		-7,72	-7,22	-6,11	-3,99	-3,89		-5,72
Sweden			-2,58	-6,50				-11,21							-6,30	-2,44	3,51	0,03	2,68		-2,88
Taiwan															4,27	7,96	9,84	9,96			8,26
United-Kingdom	1,57	3,19	1,95	5,73	3,73	2,57	1,32	-0,33	-1,46	-0,61	0,36	-0,20	1,31	0,88	2,02	2,43	3,56	6,66	6,35		2,64
USA													-12,58		-12,95	-20,65	-9,99	-11,26	-11,22		-13,25
Average	**2,21**	**1,33**	**-1,39**	**2,75**	**0,33**	**-0,22**	**-0,74**	**-3,72**	**-4,06**	**-6,16**	**-5,62**	**-4,08**	**-4,01**	**-0,19**	**0,24**	**-0,40**	**3,01**	**1,13**	**2,47**	**6,68**	**0,22**

Table 8-9 Overview of country specifications (2018)

Rank	Country	IRR	Offshore capacity	Site Capacity Factor	Electriciti price (country)	Depth	Distance from shore	CAPEX Factor
1	Japan	12,64%	530.000	36,0%	0,10	-8	14	1,05
2	Taiwan	9,96%	445.667	45,3%	0,11	-30	28	1,35
3	Ireland	8,21%	800.000	58,0%	0,06	-12	15	1,11
4	China	8,11%	624.750	38,5%	0,09	-12	15	1,07
5	United-Kingdom	6,67%	1.084.750	55,3%	0,06	-24	64	1,53
6	Denmark	6,13%	258.233	54,7%	0,06	-13	13	1,08
7	Poland	3,37%	517.500	50,1%	0,07	-30	46	1,48
8	France	2,17%	323.333	48,7%	0,05	-15	10	1,11
9	Netherlands	1,41%	379.350	51,0%	0,05	-8	24	1,10
10	Estonia	0,81%	525.000	48,0%	0,05	-11	13	1,10
11	Sweden	0,03%	282.000	46,0%	0,05	-12	9	1,09
12	Greece	-2,32%	137.210	32,8%	0,06	-8	5	1,03
13	South Korea	-3,99%	279.040	34,0%	0,05	-14	5	1,10
14	Germany	-7,50%	323.600	58,4%	0,04	-31	68	1,70
15	Canada	-8,68%	790.000	52,1%	0,03	-17	24	1,27
16	USA	-11,26%	1.376.667	53,2%	0,03	-37	35	1,45
	Worldwide	**1,14%**	**546.117**	**46,04%**	**0,06**	**-18**	**26**	**1,24**

	Value	Method
Long-term mean	0,0639	AVERAGE(F9:F26)
mean reversion speed	0,3611	Solver
volatility	0,0117	STDEV.P(F9:F26)
sum of ln	55,5558	SUM(K10:K26)

Year	Real prices	1) Real Price Change	2) Predicted Price Change	3) Model Error (1-2)	4) Norm Distribution of Errors	5) LN of Errors
2000	0,0473					
2001	0,0517	0,0044	0,0060	-0,0016	33,7817	3,5199
2002	0,0581	0,0064	0,0044	0,0020	33,5932	3,5143
2003	0,0708	0,0127	0,0021	0,0107	22,4986	3,1135
2004	0,0675	-0,0034	-0,0025	-0,0008	34,0124	3,5267
2005	0,0612	-0,0063	-0,0013	-0,0050	31,1532	3,4389
2006	0,0625	0,0013	0,0010	0,0003	34,0871	3,5289
2007	0,0590	-0,0035	0,0005	-0,0039	32,2117	3,4723
2008	0,0810	0,0219	0,0017	0,0202	7,6936	2,0404
2009	0,0772	-0,0038	-0,0062	0,0024	33,3811	3,5080
2010	0,0830	0,0058	-0,0048	0,0106	22,5722	3,1167
2011	0,0785	-0,0045	-0,0069	0,0024	33,3710	3,5077
2012	0,0704	-0,0082	-0,0053	-0,0029	33,0902	3,4992
2013	0,0754	0,0050	-0,0023	0,0074	27,9232	3,3295
2014	0,0546	-0,0208	-0,0042	-0,0167	12,3430	2,5131
2015	0,0445	-0,0100	0,0034	-0,0134	17,6845	2,8727
2016	0,0517	0,0072	0,0070	0,0003	34,0925	3,5291
2017	0,0550	0,0033	0,0044	-0,0011	33,9481	3,5248

Figure 8-1-Summary of maximum likelihood test for DK

Table 8-10 Overview and ranking of support schemes

Country	Unique Feature		Ranking
Japan	FiT	Price Scheme Paid Grid Connection	1
China	FiT	Price Scheme Paid Grid Connection	1
Taiwan	FiT	Price Scheme Paid Grid Connection	1
Ireland	FiT	Quantity Scheme 15 years eligibility period	3
Canada	FiT	Quantity Scheme	2
India	FiT	Quantity Scheme	2
UK	CFD	FiT structure but with a baseline price	4
Estonia	FiP	Yearly cap on support based on the market production Additional support beside FiP is prohibited Shortest eligibility period (12 years)	10
Denmark	FiP	Capped support level, but no floor price Additional bonus support in initial years Paid grid connection Favourable government loans fine for too slow development	6
France	FiP	Yearly support reduction based on industry cost levels Protectivistic policies	9
Germany	FiP	Longest eligibility period (20 years) Premium reviewed each month Paid grid connection Favourable government loans	5
Spain	FiP	No support cap and no chance of premium reduction participation guarantee	7
The Netherlands	FiP	sliding premium + capped maximum Paid grid connection	8
Greece	FiP	Sliding Premium Capped support level based on production	6
Sweden	Quota-System	investment support for pilot projects	12

Table 8-11 Assumptions behind our Cash flow model and valuation model, own creation

Component	Pros	Cons
Revenue	- Takes energy loss factors into account - Incorporates decreasing production - Incorporates real capacity factor and wind speed	- Assumes constant energy loss - Constant wind quality - Assumes 100% production sold - Too stable electricity prices
CAPEX	- Takes cost distribution into account - takes real distance to shore and sea depth into account - Incorporates learning curve	- Interpolations of missing data points - Does not take global differences into account - Assumed no fixed costs - Does not take economies of scale into account
OPEX	- Incorporates the learning curve	- Interpolations of missing data points - Does not take project-specific factors into account - Does not take global differences into account - Does not take economies of scale into account
Decommissioning Cost	1. Uses the unit cost as a proxy. Usually Decom cost is not part of the analysis' we have found.	**2.** Does not incorporate a learning curve 3. Does not take economies of scale into account
Valuation	4. Excludes company-specific factors	5. Excludes company-specific factors 6. Doesn't work if all cash flow is negative