OFFSHORE WIND POWER INVESTMENT MODEL USING A REFERENCE CLASS FORECASTING APPROACH TO ESTIMATE THE REQUIRED COST CONTINGENCY BUDGET

Dissertation in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE WITH A MAJOR IN ENERGY TECHNOLOGY WITH FOCUS ON WIND POWER

UPPSALA UNIVERSITY

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Department of Earth Sciences, Campus Gotland

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2015-05-22
ABSTRACT
Forecasting capital expenditures in early stages of an offshore wind power project is a problematic process. The process can be affected by optimism bias and strategic misrepresentation which may result in cost overruns. This thesis is a response to issues regarding cost overruns in offshore wind power projects. The aim of this thesis is to create a cost forecasting method which can estimate the necessary capital budget in a wind power project.

The author presents a two-step model which both applies the inside view and outside view. The inside view contains equations related to investment and installation costs. The outside view applies reference class forecasting in order to adjust the necessary cost contingency budget. The combined model will therefore forecast capital expenditures for a specific site and adjust the cost calculations with regard to previous similar projects.

The results illustrate that the model is well correlated with normalized cost estimations in other projects. A hypothetical 150MW offshore wind farm is estimated to cost between 2.9 million €/MW and 3.5 million €/MW depending on the location of the wind farm.
ACKNOWLEDGEMENTS

I would like to express my gratitude towards my supervisors Dr. Kullvén and Mr. Kaidis for their guidance and support throughout the course of this research. In addition, special acknowledgments go to Gästrike-Hälsinge nation for being a big part of my life during my years in college. Finally I would like to thank Göransson-Sandviken traveling scholarship fund for supporting me during my time in The Netherlands.
NOMENCLATURE

$\alpha, \beta \& \gamma$: Coefficients for nominal voltage level

$A_{TR}$: Rated power from the transformer

$a_{oi}$: Total length of overhead lines

$C$: Cost

$C_{ar}$: Average reference cost

$C_{CS}$: Total cost of the collection system.

$C_{DG}$: Cost of the diesel generator.

$C_e$: Estimated construction cost

$C_{SG,MW}$: Cost of switchgears

$C_{SS,f}$: Sub-station foundation cost

$C_{c,MW}$: Cost of collection system

$c_{BB}$: HV busbar

$c_{PD}$: Project development cost

$c_{SE}$: SCADA system cost

$c_{SG,HV}$: Cost of switchgears.

$c_{SG,MW}$: Switchgear cost.

$c_{SS,f}$: Cost of offshore substation platform.

$c_{TR}$: Cost of Transformer.

$c_{WT}$: Cost per turbine.

$c_{c,MW}$: Cost of the submarine cables.

$c_f$: Cost of the foundation.

$c_{l,HV}$: Installation cost of submarine HV cables.

$c_{l,MW}$: Collector investment cost / km

$c_{m,HV}$: Unit cost of submarine HV cables.

$D$: Sea depth in meters.

$d$: Rotor diameter

$d_{af}$: Average distance to shore

$d_{ps}$: Total length from shoreline to the grid

$d_{wf}$: Distance from shore.

$h$: Hub height

$I_n$: Cable ampacity [A]

$I$: Installation hours

$L$: loading time

LOAD: total loading time

$M$: intra-field movement time

Move: total trip intra-field movement time

$n_{HV}$: Number of HV circuits.

$n_{TR}$: Number of transformers.

$n_{WT}$: Number of turbines.

$n_{cl}$: Number of clusters.

$n_{o,HV}$: Amount of overhead lines

NUMUNIT: Number of turbines

NUMUNIT: number of units

$P_{WT}$: Rated power.

$r_{xy}$: Correlation coefficient

$S$: Cable section [mm2].

SDR: spread day rate

SPU: total scour per unit

TDC: total daily cost

TSR: total tonnage of scour needed

VC: vessel capacity (units/trips)

VDR: vessel day rate

$V_n$: Nominal voltage in kV.

$W$: the weather factor
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CHAPTER 1. INTRODUCTION

Chapter 1 aims to introduce the reader to the fundamentals of capital expenditures in the wind power industry. This includes a background to the research, the problem statement and the research question. In addition, justification of research will be expressed. Finally, definitions of the most common vocabulary are presented.

1.1 BACKGROUND TO THE RESEARCH

Offshore wind power projects play an important role in the European Union’s aim to reduce carbon dioxide emissions. As a result of renewable energy policies, the amount of offshore wind farms has increased rapidly during the last years. As of today, 74 wind farms are located within the borders of the European Union (Ho et al, 2014).

Wind power projects vary in size, type and design depending on geographical location and local constraints. Regardless of differences in scope, all wind power projects are subjected to extensive planning. The planning period can go on for several years with difficult investment decisions in early stages of the project. Moreover, estimating future spot prices is a problematic process, which results in difficulties in for example budgeting future cash flows (Hou, 2013). Nonetheless, wind turbine installations have experienced a remarkable increase over the last 20 years. The annual growth has been 27% per year during the period of 2000-2011 (IRENA, 2012).
Costs associated with a wind power project can be divided into two categories, capital expenditures (henceforth CAPEX) and operational expenditures (henceforth OPEX). CAPEX refers to the cost associated with the development of the wind farm. This includes planning, development, construction, balance of plant, commissioning and test operations. CAPEX transfers to OPEX on the commercial operation date of a wind farm. All future cost related to the wind farm will from the commercial operation date be defined as OPEX. (Hofmann et al, 2012).

Forecasting capital costs in wind power projects is a complicated process. Cost data from previous projects are normally confidential and wind turbine manufactures do not share their cost models due to the risk of losing competitive advantages. Furthermore, site specific conditions may differ between projects which will further increase the level of uncertainty of the overall capital cost of a wind power project (Manwell et al, 2009).

CAPEX in wind power development does not usually overrun their initial budget as much as other electricity projects. This implies that cost estimations in wind power projects are properly executed in comparison with other electricity sources. Nevertheless, according to the study “Construction Cost Overruns and Electricity Infrastructure: An Unavoidable Risk?” by Sovacool et al (2014), the average cost overrun for 35 wind farms was 7% or $33 million. A cost overrun of this magnitude will impact the net present value and internal rate of return of a wind farm. Table 1 illustrates a statistical comparison of different energy sources. Only solar power projects have a lower cost overrun according to these statistics (Sovacool et al, 2014).
Table 1 Summary of cost overruns for different electricity projects. Source: Sovacool et al (2014)

<table>
<thead>
<tr>
<th></th>
<th>Number of projects</th>
<th>Average cost escalation</th>
<th>Standard deviation</th>
<th>Average cost overrun (m$)</th>
<th>Standard cost Deviation(m$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>61</td>
<td>70,6%</td>
<td>112</td>
<td>2437</td>
<td>7054</td>
</tr>
<tr>
<td>Nuclear</td>
<td>180</td>
<td>117,3%</td>
<td>152</td>
<td>1282</td>
<td>1965</td>
</tr>
<tr>
<td>Thermal</td>
<td>36</td>
<td>12,6%</td>
<td>33</td>
<td>168</td>
<td>57</td>
</tr>
<tr>
<td>Wind</td>
<td>35</td>
<td>7,7%</td>
<td>13</td>
<td>33</td>
<td>112</td>
</tr>
<tr>
<td>Solar</td>
<td>39</td>
<td>1,3%</td>
<td>18</td>
<td>-4</td>
<td>62</td>
</tr>
<tr>
<td>Transmission</td>
<td>50</td>
<td>8%</td>
<td>40</td>
<td>30</td>
<td>217</td>
</tr>
</tbody>
</table>

Capital costs in wind power projects can be estimated in several ways. Firstly, the investment cost and installation cost can be calculated using a cost calculation approach. This approach examines each cost driver which later is summarized as the total estimate project cost. This method requires high quality site-specific data. Moreover, the cost calculation approach is subjected to optimism bias and strategic misrepresentation which can result in a deficient cost contingency level (Flyvbjerg, 2011).

Secondly, a reference class forecasting method can be utilized. This methodology is based on a reference class of existing projects which will be used as a source to estimate the cost of a future project. The methodology is a development of Daniel Kahnemans finding on human judgment and decision-making for which he received the noble price in 2002 (Kaiser & Snyder, 2012).

Thirdly, a learning curve can be derived in order to predict capital costs. This method is based on economies of scale, which refers to the reduced cost per unit when a component is produced in large quantities (Manwell et al, 2009).

Cost contingency planning is a critical process which seeks to identify incertitude in major construction projects. Identifying risks and uncertainties within a power project is necessary in order to dedicate a correct amount of contingency in the project budget (Molenaar et al, 2010).
This thesis is a response to unknown and known uncertainties estimating capital costs in offshore wind power projects. The author aims to estimate future CAPEX in wind power development using a combination of the cost calculation method and the reference class forecasting approach.

1.2 PROBLEM STATEMENT

The development of an offshore wind power plant is a multi-disciplinary process of high complexity. The development process usually lasts for years and critical investment decisions must be made in early stages. In order to examine the financial feasibility of a potential project, capital cost estimations need to be made without all the necessary information available. In these cases, information and experience from previous projects combined with the project specific information available is the only way to make an estimation of the capital costs of a project. The scientific literature highlights a number of ways to forecast CAPEX for offshore wind power projects. Nevertheless, a gap can be distinguished in the research in the matter of forecasting CAPEX.

It can be seen in section 1.1 that wind power projects are subjected to cost overruns. In addition, the author can find little or no research on the topic of reference class forecasting in offshore wind power projects. Reference class forecasting has been implemented in a number of civil engineering projects in Denmark and the UK with positive feedback (Flyvbjerg, 2006). Due to the fact that wind power development is subjected to similar matters as civil engineering, the methodology should be applicable to the wind power industry as well. Nonetheless, the method needs to be adapted to the context of wind power engineering. In order to produce legitimate results, further research needs to be performed in this matter.
1.3 RESEARCH PURPOSE

The aim of the thesis is to:

1. Develop a methodology that will assist with investment decisions for offshore wind power project.
2. Introduce the reference class forecasting method for offshore capital expenditures.
3. Increase cost forecast accuracy by combining cost calculations and cost adjustment methods for offshore wind power projects.

1.4 RESEARCH QUESTION

The thesis aims to answer the following research question:
A1. How can a cost contingency budget in wind power projects be estimated and modeled?

In addition, the author aims to answer the following sub research questions:
B-1. What does the research trends say about cost forecasting?
B-2. How does the latest research explain cost overruns?
C-1. How can CAPEX in offshore wind power projects be estimated using a cost calculation approach?
C-2. How can CAPEX in offshore wind power projects be forecasted using the reference class forecasting method?
D-1. How can a cost calculation approach and reference class forecasting method be combined to estimate CAPEX in offshore wind power projects?
E-1. What recommendations can be made when forecasting CAPEX in offshore wind power projects?
E-2. How can the reference class forecasting method increase budget accuracies for offshore wind power projects?
F-1. Is reference class forecasting applicable in offshore wind power cost contingency
The author aims to answer the main research question in the following way:

The author argues that the process of forecasting capital expenditures in wind power projects can be improved using a reference class forecasting method in combination with the cost calculation approach.

Answers to the sub-research questions can be found in the end of each chapter:

- Question F-1 will be answered in the 5th chapter “Discussion and analysis”.
- Question B-1 & B-2 will be answered in the 2nd chapter, “Literature review”.
- Question C-1 & C-2 will be answered in the 3rd chapter “Methodology and data”.
- Question D-1 will be answered in the 4th chapter “Application of the methodology and results”.
- Question A1, E-1 & E-2 will be answered in the 6th chapter “Conclusions”

1.5 DELIMITATIONS OF SCOPE AND LIMITATIONS

This study will analyze the necessary level of contingencies for offshore wind power development. It will not include a full cost breakdown for each of the projects nor will it analyze the financial suitability for a project. The reference class forecasting method will not estimate site specific conditions or unknown risks that can occur in the project. It is mainly a method to estimate a project’s cost estimations in comparison to similar projects.
Derived results only serve as a guideline for CAPEX estimations in early stages of an offshore wind power project. This research is mainly focused on the screening and feasibility phases where little or no procurements have been performed.

In order to produce more legitimate results, additional data sets needs to be gathered. The author recommends professionals who plan to apply this model to define a more site specific reference class.

1.6 DECLARATION AND JUSTIFICATION FOR THE RESEARCH

The author aims to create a transparent thesis by addressing the advantages and limitations in the research. One needs to be aware of the following facts. Firstly, data sets used to compile the results are of secondary nature. This may or may not reduce the legitimacy of the findings. Secondly, applicable theories only act as strategies for estimating future CAPEX. Site specific data needs to be gathered in order to forecast CAPEX in a more precise way. Thirdly, the established model merely serves as recommendation for future research.

As specified in section 1.3, the aim of this study is to develop a methodology that will assist with investment decisions for offshore wind power project. Hence, the main contribution is the model and not the results. Results are dependent on the used dataset and are expected to be different depending site specific conditions and established reference class.

1.7 CONCLUSIONS

Chapter one has provided information regarding the research gap in forecasting capital expenditures for wind power projects. Research problem, research aim and research questions have been presented. Finally, a declaration of the research method is
illustrated. The author highlights the importance of transparency throughout the thesis.

The outline of the thesis is as follows:

Chapter one, *introduction*, aims to define the context CAPEX in offshore wind power development. Research aim and research questions are included in this chapter. It also contains a terminology section to assist the reader.

Chapter two, *the literature review*, will guide the reader through relevant literature. The aim of this chapter is to provide information within the context of cost estimations for offshore wind power development.

Chapter three, *methodology and data*, will clarify how the study was performed. The purpose is to present a transparent research approach which aims to guide the reader through different research methods. In addition, applicable empirical data will also be illustrated.

Chapter four, *application of the methodology and results*, depicts derived results for the investment costs associated with wind power investments, installation costs and a reference class for offshore wind power in the European Union. The application of the results is based on the defined methodology in the previous chapter.

Chapter five, *discussion and analysis*, discusses the results from the precious chapter. The analysis aims to express the authors’ opinion regarding implementation of reference class forecasting in offshore wind power development.

Chapter six, *conclusions*, will answer the main research question. Limitations of the research are provided. Finally, recommendations for future research are discussed.
A summary of the most common terminology is defined below:

**Strategic misrepresentation**

Strategic misrepresentation explains cost forecasting errors by accusing decision makers to deliberately and strategically misjudge benefits associated with an investment.

**Optimism bias**

Optimism bias is a syndrome which is common on organizations. Optimism bias occurs when decision makers underestimate the cost of a project or overestimate the benefits of an investment.

**Cost overrun uplift**

The percentage of added cost contingencies to minimize the risk of cost overrun.

**Inside view**

A cost forecasting method that focuses on the specific details within a project.

**Outside view**

A cost forecasting method that focuses on experience from similar projects.

**Cost contingency**

The amount of cash reserves in a budget to cope with unexpected costs in a project.
CHAPTER 2. LITERATURE REVIEW

Chapter 2 aims to orientate the reader through the theoretical framework which is applicable for offshore CAPEX estimations. The first part of this chapter will introduce an overview of CAPEX for offshore wind farms. The second part will describe different reasons for inaccurate cost forecasts. The third part will introduce a theoretical framework for a three-way approach when calculating and adjusting CAPEX for offshore wind farms. The main sources for CAPEX forecasting are as follows:


**Adjusting for bias decisions:** Flyvbjerg & Techn (2006). From Nobel Prize to Project Management: Getting Risks Right. Project Management Journal. 37

The following sub-research questions will be answered in chapter 2.

- B-1. What does the research trends say about cost forecasting?
- B-2. How does the latest research explain cost overruns?

---

**2.1 CAPITAL EXPENDITURES FOR OFFSHORE WIND POWER DEVELOPMENT**

To identify and estimate the cost of offshore wind power investments, a cost breakdown will need to be performed. The cost breakdown will represent the accounts in the project budget. Figure 1 illustrates a CAPEX breakdown for two 300 MW offshore wind farms.
Appendix 1 features a full cost breakdown structure of a wind farm. A cost breakdown summary containing six main categories is illustrated below.

- Development costs accounts for 30% to 5% of the total investment.
- The turbine stands for 40% to 50% of the cost.
- The cost of foundations is estimated to be 10 to 20% of the investment cost.
- Installation and commissioning account for 6% to 20% of the total investment.
- Electrical infrastructure lies in the spectrum of 10% to 23% of the total cost.
- Other costs refer to logistics and storage cost associated with development and installation. Other costs account for 1% to 5% of the total investment.

![Cost breakdown for two offshore wind farms](image)

The cost of offshore wind power has been increasing over the last two decades. A more intense cost increase has occurred since 2007. Figure 1 illustrates normalized CAPEX
for offshore wind farms since 2000. A number of factors are connected to the rapid cost increase in previous years. The cost drivers are as follows:

- The growing demand of onshore wind turbines in the world. This resulted in a fall in the supply of offshore turbines. Hence, turbine manufactures have not been able to increase the production of turbines to same extent as the number of executed wind power projects.
- Fluctuations in microeconomic drivers. These include changes in the cost of labor, commodity prices and exchange rates.
- Limited number of installation vessels available.
- Corporate modifications in two offshore wind turbine suppliers.
- Amplified knowledge of offshore wind turbine design. Thus, the prices of turbines have increased.
- The location of wind offshore wind farms tend to move further away for shore. In addition, foundations are being built in deeper waters which results in higher capital costs (Levitt et al, 2011).

![Figure 2 Total investment cost for offshore projects. Source: Taylor et al (2015).](image)
2.1.1 COST DRIVERS IN OFFSHORE WIND POWER DEVELOPMENT
Forecasting capital expenditures for offshore wind power projects is a difficult process. A number of parameters influence the cost of the project. Planning and development cost is affected by the size of the wind farm. One parameter which will influence the development cost is the number of met mast needed to analyze the wind characteristics at a site. Offshore wind measurement will be significantly more expensive than onshore measurement costs. This is due to difficulties in assembling met mast offshore. Moreover, environmental impact assessments become more difficult and costly with increasing wind farm sizes. Figure 3 shows a regression plot of offshore wind farms. The trend line indicates that normalized CAPEX increase with the size of the wind farm (Renewables Advisory Board, 2011).

![Figure 3 Regression line demonstrating cost as a result of capacity increase. Source: Kaiser & Snyder (2012)](image)

Turbine costs are closely correlated with market dynamics, both in terms of wind industry demand and international commodity prices. Wind turbine prices will follow the general learning curve of the industry. However, fluctuations in turbine prices are common. Price fluctuations are a response to supply and demand parameters on the market. With increasing amount of wind turbine manufactures and better-established supply chains, wind turbine price are forecasted to drop by 20% to 2020. Essential commodities in turbine manufacturing are fiberglass, mild steel, ductile cast iron, and
copper. Commodity prices have been subjected to fluctuations which increases the uncertainty level of the turbine cost. Figure 4 illustrates a regression line for commodity prices and the cost of offshore wind power. The plot gives the indication that the cost of steel impacts the cost of wind turbines (Renewables Advisory Board, 2011).

Balance of plant cost variations is correlated with commodity prices, especially steel and concrete prices. Furthermore, foundation costs depend on the type of soil or water depth. Electricity systems and transmission lines costs also play a vital role in price variation. Figure 5 shows a regression line for normalized CAPEX and sea depth. The plot shows a correlation between increased CAPEX and sea depth (Renewables Advisory Board, 2011).
For offshore wind farm installations, costs are dependent on the vessel chartering costs. The vessel chartering cost is correlated with market dynamics and distance to wind farm. Moreover, the impact of severe weather will increase delays on a project, which can result in substantial cost overruns. Figure 6 illustrates a regression line for normalized CAPEX and distance to wind farm from shore. The plot shows the increased CAPEX with greater distances between wind farm and shoreline (Renewables Advisory Board, 2011).

Trend lines in Figure 3, Figure 4, Figure 5 and Figure 6 illustrate a correlation between cost escalations, the size of a wind farm, distance to shore and water depth. However, cost overruns feature a different story. Figure 7 shows a bubble diagram with cost overruns on the x-axis and frequency distribution and the y-axis. The size of the bubbles represents the capacity of the wind farm. As shown in the plot, close to 30% of the projects did not encounter a cost overrun. Furthermore, no statistical relationship can be derived regarding the size of the wind farm and cost overrun.
2.2 INACCURACY IN COST FORECASTING

Underperformance such as cost overruns can be explained by causes and root causes. Conventionally, causes of underperformance may be described as a result of the complexity of the project, changes in the project scope, technical uncertainty, unexpected events and organizational issues. However, these are not root causes. The root cause of deficit and cost overrun is the fact that planners tend to scientifically misjudge the risks involved in projects. This behavior will from now on be coined as optimism bias (Flyvbjerg, 2011).

Studies examine inaccuracies in cost estimations in civil work planning management (Flyvbjerg 2002, 2003, 2005). Their findings suggest that little improvement in cost forecasting has happened during the last 70 years. Nevertheless, numerous claims have
been made on new and improved forecasting methods. In addition to the claims of better forecasting methods, the internet revolution has improved access to reliable data. This should increase the likelihood of more accurate cost forecasts (Flyvbjerg & Techn, 2006).

A study on infrastructure projects during a 70 year period demonstrates difficulties in capital cost forecasting. The study shows that transportation infrastructure projects have a cost increase by 44.7%, bridges and tunnels encountered an average increased cost by 33.8% and road infrastructure projects exceeded the initial budget by 20.4%. The authors could not find any data that suggest lower cost overruns during this period. These findings suggest that no cost forecasting improvements have transpired during this time span. The authors also suggest that transportation project is no worse than other type of big engineering projects. In order to understand incorrectness in cost forecasting, three different reasons need to be taken into consideration. These are as follows; technical reasons, psychological reasons and political reasons. (Flyvbjerg & Techn, 2006).

2.2.1 TECHNICAL REASONS FOR COST OVERRUNS
Technical factors are the most common type of explanation for inaccuracy in cost forecasts. There are two primary reasons for technical forecast failures, the use of unfitting models and the use of incorrect data. In addition, honest mistakes will also increase the number of incorrect forecasts (Vanston & Vanston, 2004).

Technical explanations for errors in cost estimations can take shape in different forms. Firstly, the problem may be due to imperfect information. Secondly, scope changes tend to increase the cost of a project. Thirdly, poor initial documentation may lead to incorrect decision which ultimately will result in cost overruns (Flyvbjerg, 2004). Explaining inaccurate forecast by technical factors seems logical. However, research shows that there are more to it than honest mistakes and bad data.
There are several questions which need to be answered before one can attribute cost forecasting inaccuracies exclusively to technical factors. The first issue, which needs to be raised, is the distribution chart of inaccurateness. If technical explanations are valid as the only explanation for cost overruns, then these plots would have a normal distribution. However, when analyzing cost data for civil engineering projects, one finds that distribution plots have a non-normal profile. The second issue which needs to be taken into consideration is the improvement of cost forecasting models over time. A range of cost forecasting models have been established during the last 70 years. Yet, no improvements in cost forecasting accuracy can be traced. In addition, the availability of reliable data has been increasing due to the internet revolution. This should suggest that cost estimations have been improved in recent years. Nevertheless, no improvements in cost forecasting accuracy have been made (Flyvbjerg & Techn, 2006).

These questions imply that there are more reasons to incorrect forecasts than technical errors and unreliable data. Researchers are now looking for the root cause of the problem. Their findings suggest that these problems originate from psychological and political factors (Flyvbjerg & Techn, 2006).

### 2.2.2 PSYCHOLOGICAL REASONS FOR COST OVERRUN

As indicated in the previous section, there must be other reasons for inaccurate forecasts than incorrect models. Flyvbjerg (2011) explains underperformances in terms of optimism bias and strategic misrepresentation. Optimism bias refers to a psychological syndrome coined as planning fallacy which seems to be common in organizations.

Planning fallacy transpires when a manager evaluates future cash flows more positive than is reasonable. In its essence, investment decisions are based on delusional optimism rather than on probabilities and statistical evaluations. As a result, paybacks with an investment decision have a tendency to be overestimated. In contrast, cost overruns associated with investments are neglected (Morris et al, 2011).
Decision errors can be explained through optimism bias. The bias is often a result of utilizing the inside view in cost forecasting. The inside view aims to estimate future cost by analyzing the uniqueness of a single project. Project managers are focused on project specific obstacles by creating different scenarios of the future. One example of optimism bias is an experiment on psychology students. The students were asked to predict the time it would take to write their honors thesis. The experiment revealed that 70% of the students took longer time than what they initially predicted (Flyvbjerg, 2011).

Optimism bias is not restricted to this single experiment. Cost overruns can be found within many different types of organizations. Various studies show that cost estimations have a high tendency to be underestimated. When asking managers about errors in cost estimations, they tend to mention reasons like scope changes, complexity and technological factors as the main reason for a cost overrun. Thus, optimism bias may not be analyzed as a source of forecasting error (Flyvbjerg, 2011).

Optimism bias would be a legit explanation for explaining forecasting errors if cost estimations were performed by junior executives. However, it seems logical that big investment projects go through a peer-review process where senior forecasters are involved. Therefore, optimism bias cannot be ruled as a single explain of cost overruns. The next section will continue the analysis to further understand which factors affect errors in cost overruns.

2.2.3 POLITICAL REASONS FOR COST OVERRUN
The second root cause for ambiguous planning is coined as strategic misrepresentation. Strategic misrepresentation describes forecasting errors in terms of political and agency issues (Flyvbjerg, 2011).
Strategic misrepresentation explains forecasting errors by accusing decision makers to deliberately and strategically misjudge benefits associated with an investment. The source of misjudged benefits is the attempt to increase the probability that their project will win the procurement. This behavior can result in the promotion of projects that are unlikely to stay within the frames of the budget (Flyvbjerg, 2011).

Strategic misrepresentation can be traced back to organizational and political stress. Decision makers may compete over scarce funds. In order to win a project, they tend to overestimate the benefits and underestimate the costs. Hence, deliberate strategic misrepresentation can be defined as a lie. Studies show that there exist strong incentives for managers to receive project approval. Incentives may be that managers seek to clime the hierarchy ladder. It can also be the lack of resources which forces them to promote projects with low financial profits. Managers know that branding a project in positive way will increase the possibility to receive funds for a project (Flyvbjerg, 2004).

Studies on civil management executed in the UK and US show strong incentives for managers to promote projects as favorably as possible. Local authorities, developers, unions, politicians and consultants will all benefit from a project approval. Therefore, little or no peer reviewing is being performed in order to minimize bias of a budget. The following equation can is used by managers in order to secure foundlings for a project.

\[
\text{Underestimated costs} + \text{overestimated benefits} = \text{Project approval}
\] (1)

Applying equation 1 will result in the approval of bad projects. Hence, it is not the best project that will receive founds funds. Instead, projects which are best branded will get approved. The result of strategic misrepresentation in the context of investment decisions can therefore result in cost overruns and reduced profit margins (Flyvbjerg, 2004).
To fully understand why mega projects have a habit of exceeding the initial budget, a combination of technical, psychological and political reasons needs to be taken into account. One reason does not omit another. In the following sections, a method for mitigating the risk of cost overruns will be presented.

2.3 THE INVESTMENT COST CALCULATION APPROACH IN MODELING OFFSHORE WIND POWER CAPEX.

Dicorato et al (2011) outlines a comprehensive approach for estimating offshore investment costs. Their cost estimation approach includes the design phase, developing phase, procurement phase and startup phase. Installation cost calculations will not be utilized in this chapter. However, estimating installation costs will be described in section 2.4. Equations are derived from empirical data.

2.3.1 COST OF TURBINE

The cost for a 2 – 5MW fully-equipped offshore wind turbine can be estimated using equation 2. Equation 2 was derived using empirical data from the report “Study of the costs of offshore wind generation” by DTU (2007). The result of equation 2 is well in line with the turbine cost for the offshore wind farms Arklow Bank (Douglas-Westwood Ltd & ODE Ltd, 2005) and Barrow (Bellone & Dale, 2006).

\[
c_{WT} = 2.95 \times 10^3 \times \ln(P_{WT}) - 375,2 \quad (k\varepsilon)
\]  

- \(c_{WT}\) : Cost per turbine.
- \(P_{WT}\) : Rated power (Dicorato et al, 2011).

2.3.2 COST OF FOUNDATION

The cost of a foundation depends on the manufacturing method. The following equation can be used to estimate the cost for monopile foundation. Equation 3 is based on data
from “Offshore wind farm layout optimization (OWFLO) project: an introduction” (Elkinton et al, 2005).

\[
c_f = 320 P_{WT} (1 + 0.02(D - 8))(1 + 0.8 * 10^{-6} \left( h \left( \frac{d}{2} \right)^2 - 10^{-5} \right)) \text{[}k\text{€/turbine]} \tag{3}
\]

- \( c_f \): Cost of the foundation.
- \( D \): Sea depth in meters.
- \( P_{WT} \): Rated power.
- \( h \): Hub height
- \( d \): Rotor diameter (Dicorato et al, 2011).

### 2.3.3 COST OF COLLECTION SYSTEM

The cost of copper cables is provided in per unit length. Cross-linked polyethylene copper cables are normally used for offshore electric system. For submarine cables, equation 4 is used to estimate the cost. Least-squares linear regression equation 4 is derived with respect to data from (ABB Xlpe, 2015) and (Green et al, 2007).

<table>
<thead>
<tr>
<th>S (mm²)</th>
<th>Cost coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>95</td>
<td>0.4818</td>
</tr>
<tr>
<td>120</td>
<td></td>
</tr>
<tr>
<td>150</td>
<td></td>
</tr>
<tr>
<td>185</td>
<td></td>
</tr>
<tr>
<td>240</td>
<td></td>
</tr>
<tr>
<td>300</td>
<td></td>
</tr>
<tr>
<td>400</td>
<td></td>
</tr>
<tr>
<td>500</td>
<td></td>
</tr>
<tr>
<td>630</td>
<td></td>
</tr>
</tbody>
</table>

\[
C_{c,MW} = 0.4818 S + 99,153 \text{ [}k\text{€/km]} \tag{4}
\]

- \( C_{c,MW} \): Cost of the collection system.
- \( S \): Cable section [mm²] cost coefficient, see Table 2.

The total cost of the collection system is derived through:

\[
C_{CS} = \sum S \left( (C_{c,MW} + C_{i,MW}) l(S) \right) \tag{5}
\]
• $c_{c,MW}$: Cost of the submarine cables.
• $C_{CS}$: Total cost of the collection system.
• $l(S)$: Total cable length of section S.
• $c_{l,MW}$: Constant 365 k€/km.

2.3.4 COST OF INTEGRATION SYSTEM

The cost of an offshore substation can be calculated using equation 6 for systems up to 150MVA. The main cost for the integration system is the MV/HV transformer. Equation 6 is provided by Lundberg (2003).

$$c_{TR} = -153,05 + 131,1A^{0.4473}_{TR} \text{ [k€]}$$ (6)

• $c_{TR}$: Cost of the transformer.
• $A_{TR}$: Rated power from the transformer.

Lazaridis (2005) established equation 7 for calculating the cost of MV/HV transformers to be in the range of 50 to 800 MVA.

$$c_{TR} = 42,688A^{0.7513}_{TR} \text{ [k€]}$$ (7)

• $c_{TR}$: Cost of Transformer.
• $A_{TR}$: Rated power from the transformer.

The cost of the switchgears in a substation is correlated with the electrical scheme. Lundberg (2003) recommends applying equation 8 when estimating the cost of switchgears.
Diesel generators will be needed to support essential control systems in an offshore wind farm. The recommended size for ancillary devices is 15-20 KW per installed MW. The cost of diesel generators up to 2MW can be estimated through equation 9 which is derived from Americas Generators Inc (2015).

\[ c_{DG} = 21,242 + 2,069n_{WT}P_{WT} [k\€] \]  

- \( c_{DG} \): Cost of diesel generator.  
- \( n_{WT} \): Number of turbines.  
- \( P_{WT} \): Rated power of turbines.

Lundberg (2003) presents equation 10 to estimate the cost a of an offshore substation platform.

\[ c_{SS,f} = 2534 + 88,7 + n_{WT}P_{WT} [k\€] \]  

- \( n_{WT} \): Number of turbines.  
- \( c_{SS,f} \): Cost of offshore substation platform.  
- \( P_{WT} \): Rated power (Dicorato et al, 2011).

The total cost of an offshore substation \( C_{IS} \) is calculated through:

\[ C_{IS} = n_{TR} \times c_{TR} + (n_{cl} + n_{TR})c_{SG,MW} + n_{HV}(2c_{SG,HV} + c_{BB}) + (C_{DG} + C_{SS,f}) \]  

- \( n_{TR} \): Number of transformers.  
- \( c_{TR} \): Cost of transformers.
- \( n_{cl} \): Number of clusters.
- \( c_{SG,MW} \): Switchgear cost.
- \( n_{HV} \): Number of HV circuits.
- \( c_{BB} \): HV busbar which can be found in Table 3
- \( C_{DG} \): Cost of the diesel generator.
- \( C_{SS,f} \): Sub-station foundation cost (Dicorato et al, 2011).

### Table 3 HV bus bar and switchgear cost [k€] Source: Dicorato et al (2011).

<table>
<thead>
<tr>
<th>Vn[kV]</th>
<th>Insulation system</th>
<th>Single (SB)</th>
<th>Double Bus bar (DB)</th>
<th>SB</th>
<th>DB</th>
</tr>
</thead>
<tbody>
<tr>
<td>150</td>
<td>AIS</td>
<td>1780</td>
<td>2350</td>
<td>439</td>
<td>450</td>
</tr>
<tr>
<td></td>
<td>GIS</td>
<td>2650</td>
<td>3280</td>
<td>920</td>
<td>950</td>
</tr>
<tr>
<td>230</td>
<td>AIS</td>
<td>1736</td>
<td>2550</td>
<td>637</td>
<td>650</td>
</tr>
<tr>
<td></td>
<td>GIS</td>
<td>2900</td>
<td>3450</td>
<td>1250</td>
<td>1300</td>
</tr>
</tbody>
</table>

Transmission cost \( C_{TS} \) for offshore substation is derived through:

\[
C_{TS} = n_{HV} (c_{m,HV} + c_{i,HV}) d_{wf} + n_{HV} c_{uc,HV} (1-a_{ol}) d_{ps} + n_{ol,HV} * c_{ol,HV} * a_{ol} * d_{ps} + n_{HV} * c_{SG,HV}
\]

- \( n_{HV} \): Number of HV circuits.
- \( c_{m,HV} \): Unit cost of submarine HV cables.
- \( c_{i,HV} \): Installation cost of submarine HV cables.
- \( d_{wf} \): Distance from shore.
- \( n_{ol,HV} \): Amount of overhead lines
- \( d_{df} \): Average distance to shore
- \( d_{ps} \): Total length from shoreline to the grid
- \( a_{ol} \): Total length of overhead lines.
- \( n_{HV} \): Number of HV circuits.
- \( c_{SG,HV} \): Cost of switchgears (Dicorato et al, 2011).
### 2.3.5 COST OF TRANSMISSION SYSTEM

#### Table 4 Cost coefficients for submarine AC cables

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>$\alpha$ [k€/km]</th>
<th>$\beta$ [k€/km]</th>
<th>$\gamma$ [1/A]</th>
</tr>
</thead>
<tbody>
<tr>
<td>30 - 36 kV</td>
<td>52.08</td>
<td>75.51</td>
<td>237.34</td>
</tr>
<tr>
<td>132 kV</td>
<td>249.72</td>
<td>26.48</td>
<td>379.5</td>
</tr>
<tr>
<td>230 kV</td>
<td>403.02</td>
<td>13.94</td>
<td>462.1</td>
</tr>
</tbody>
</table>

When an offshore wind farm is using an offshore substation, the transmission system will both be located offshore and onshore. Lundberg (2003) provides equation 13 to calculate the cost of submarine cables.

$$C_{c,MW} = \alpha + \beta e^{\left(\frac{\gamma I_n}{10^6}\right)} [k€/km] \quad (13)$$

- $C_{c,MW}$: Cost of collection system.
- $I_n$: Cable ampacity [A]
- $\alpha, \beta$ & $\gamma$: Coefficients for nominal voltage level. The coefficients can be found in Table 4 (Dicorato et al, 2011).

#### Table 5 Onshore HV cables and lines cost.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>50</td>
<td>210</td>
<td>270</td>
<td>350</td>
<td>410</td>
<td>250</td>
<td>1600</td>
</tr>
<tr>
<td>230</td>
<td>340</td>
<td>350</td>
<td>620</td>
<td>450</td>
<td>400</td>
<td>1950</td>
</tr>
</tbody>
</table>
2.3.6 COST OF GRID INTERFACE
Shunt regulation devices $c_r$ is estimated to cost two-thirds of the power transformer. For shunt capacitor $c_c$ the cost is on average 19 k€/MVAr. The total cost for $SVCc_{SVC}$ is estimated to be 77 k€/MVAr. In addition, the average cost for a SCADA/EMS system is estimated to be 75 k€/turbine if assuming the cost expressed by Gerdes et al (2005) and Morgan et al (2003).

The cost of SCADA/EMS is derived through:

$$C_{SE} = n_{WT} \times c_{SE}$$

- $n_{WT}$: Number of turbines.
- $c_{SE}$: 75 k€/turbine (Dicorato et al, 2011).

2.3.7 PROJECT DEVELOPMENT
Project development cost $c_{PD}$ can be estimated to be between 2% and 4% of the total investment cost (Nielsen, 2003) (Li, 2000). Furthermore, Douglas-Westwood Ltd & ODE Ltd (2005) express the development cost to be 48 k€/turbine whereas Morgan et al (2003) defines the average development cost to be 45.6 k€/MW. An average cost of 46.8 k€/MW will be used in this case. The offshore project development cost is calculated by:

$$C_D = n_{WT} \times P_{WT} \times c_{PD}$$

- $n_{WT}$: Number of turbines
- $P_{WT}$: Rated power
- $c_{PD}$: 46.8 k€/KW (Dicorato et al, 2011)
2.3.8 COMBINED INVESTMENT COST MODEL

The total investment cost model is derived using equation 2 through 15. Equation 16 is a combination of previous equations.

\[ C_t = C_p + C_D \]  

- \( C_p \) : Plant cost in €
- \( C_D \) : Development cost in €.

\( C_p \) is derived through equation (17):

\[ C_p = C_{WT} + C_f + C_{CS} + C_{IS} + C_{TS} + C_{RPR} + C_{SE} \]  

- \( C_p \) : Plant cost in €.
- \( C_{WT} \) : Cost of wind turbines.
- \( C_f \) : Cost of foundations.
- \( C_{CS} \) : Total cost of the collection system.
- \( C_{IS} \) : Total integration system cost.
- \( C_{TS} \) : Transmission system cost.
- \( C_{RPR} \) : Cost of reactive power regulation devices.
- \( C_{SE} \) : Cost of the SCADA/EMS system (Dicorato et al, 2011).

2.4 OFFSHORE WIND INSTALLATION COSTS

Section 2.4 aims to present a comprehensive method for estimating installation cost of an offshore wind farm. System generation capacity is the main driver for CAPEX since the size and number of turbines controls the amount of vessels needed. Generation capacity is related to the location of the wind farm. Moreover, generation capacity determines the amount of necessary cables and sub-stations. The total travel time required for the installation vessel is calculated through equation 18 (Kaiser & Snyder, 2012).
Turbine capacity predetermines the total number of turbines required. Moreover, the capacity of a turbine affects the size of the foundation. Hence, turbine capacity regulates the maximum water depth, soil type and vessel requirements. Turbine size will also regulate the inner-array cable length. Total turbine installation time is derived through equation 19 (Kaiser & Snyder, 2012).

\[
\text{TRAVEL} = 2\left(\frac{D}{S}\right)
\]  

(18)

- TRAVEL : Total trip installation time
- S : speed of vessel
- D: distance to port.

Turbine capacity predetermines the total number of turbines required. Moreover, the capacity of a turbine affects the size of the foundation. Hence, turbine capacity regulates the maximum water depth, soil type and vessel requirements. Turbine size will also regulate the inner-array cable length. Total turbine installation time is derived through equation 19 (Kaiser & Snyder, 2012).

\[
\text{INSTALL} = \text{VC} \times \text{I}
\]  

(19)

- INSTALL : hours
- VC : vessel capacity (units/trips)
- I : installation hours, see Table 6

Distance to port determines the amount of times the vessel needs to be used. The number of trips is linked to wind farm size, installation method and vessel spread. The installation time will be different for foundation, turbine and inner-array cable installations. The load time for a turbine is calculated by equation 20 (Kaiser & Snyder, 2012).

\[
\text{LOAD} = \text{VC} \times \text{L}
\]  

(20)

- LOAD : total loading time
- VC : vessel capacity (units/trips)
• L: loading time

Table 6: Foundation installation time as a function of turbine capacity.

<table>
<thead>
<tr>
<th>Turbine capacity (MW)</th>
<th>Installation time range, I (h)</th>
<th>Installation time expected value, I (h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.5</td>
<td>36–48</td>
<td>40</td>
</tr>
<tr>
<td>3</td>
<td>36–72</td>
<td>54</td>
</tr>
<tr>
<td>3.6</td>
<td>48–72</td>
<td>60</td>
</tr>
<tr>
<td>4</td>
<td>72–96</td>
<td>84</td>
</tr>
<tr>
<td>5</td>
<td>96</td>
<td>96</td>
</tr>
</tbody>
</table>

Distance to shore regulates the length of the export cable. The length of the inner array cable and number of substations are determined by generation capacity and distance to between turbines. The total intra-movement time is calculated through equation 21 (Kaiser & Snyder, 2012).

\[ MOVE = VC \times M \]  

\[ (21) \]

• Move: total trip intra-field movement time
• VC: vessel capacity (units/trips)
• M: intra-field movement time

The sum of the following equations results in the total time per trip for the installation procedure. The total trip time is calculated through equation 22.

\[ TRIP = TRAVEL + LOAD + INSTALL + MOVE \] (Kaiser & Snyder, 2012).  

\[ (22) \]
Table 7 Turbine installation time by capacity and vessel type. Source: Kaiser & Snyder (2012).

<table>
<thead>
<tr>
<th>Turbine capacity (MW)</th>
<th>Vessel type</th>
<th>Installation time range, I (h)</th>
<th>Installation time expected value, I (h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.5–3</td>
<td>LB</td>
<td>72–96</td>
<td>84</td>
</tr>
<tr>
<td></td>
<td>JU</td>
<td>48–72</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>SPIV</td>
<td>36–48</td>
<td>42</td>
</tr>
<tr>
<td>3–4</td>
<td>LB</td>
<td>96–120</td>
<td>108</td>
</tr>
<tr>
<td></td>
<td>JU</td>
<td>60–96</td>
<td>72</td>
</tr>
<tr>
<td></td>
<td>SPIV</td>
<td>48–60</td>
<td>54</td>
</tr>
<tr>
<td>4–5</td>
<td>LB</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>JU</td>
<td>72–120</td>
<td>96</td>
</tr>
<tr>
<td></td>
<td>SPIV</td>
<td>60–96</td>
<td>72</td>
</tr>
</tbody>
</table>

The total vessel trip time needs to be revised by a weather factor. This is due to the fact that installation vessels only operate within certain wind speeds and wave heights. A weather factor of 1 indicates that there are no delays due to weather. A weather factor of 0 indicates that the vessel will not be able to operate at any time at a specific location. Equation 23 is adjusts the trip time in accordance to the weather factor.

\[
ADJTRIP = TRIP \times \left( \frac{1}{W} \right) 
\]  

- \( W \): the weather factor

Table 8 Parameterization range for factors influencing turbine installation time. Source: Kaiser & Snyder (2012).

<table>
<thead>
<tr>
<th>Model</th>
<th>Load time, L (h)</th>
<th>Installation time, I (h)</th>
<th>Movement time, M (h)</th>
<th>Weather uptime, W (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Self-transport</td>
<td>2–6</td>
<td>36–120</td>
<td>4–8</td>
<td>75–90</td>
</tr>
</tbody>
</table>

Table 9 Parameterization range for factors influencing foundation installation time. Source: Kaiser & Snyder (2012).

<table>
<thead>
<tr>
<th>Model</th>
<th>Load time, L (h)</th>
<th>Installation time, I (h)</th>
<th>Movement time, M (h)</th>
<th>Weather uptime, W (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Self-transport</td>
<td>2–4 (3)</td>
<td>36–96 (72)</td>
<td>4–8 (6)</td>
<td>75–95 (90)</td>
</tr>
<tr>
<td>Barge</td>
<td>NA</td>
<td>36–96 (72)</td>
<td>NA</td>
<td>75–95 (90)</td>
</tr>
</tbody>
</table>
The number of trips to the site is calculated through equation (24). The number of trips is a function of vessel capacity and number of turbines in the farm.

\[ NUMTRIP = \frac{NUMUNIT}{VC} \]  

- \( NUMUNIT \): Number of turbines
- \( VC \): Vessel capacity

The total installation time is calculated through equation 25. The installation time is a function of the adjusted weather factor and number of trips (Kaiser & Snyder, 2012).

\[ INTIME = ADJTRIP \times NUMTRIP \]  

- \( INTIME \): Installation time
- \( ADJTRIP \): Adjusted trip time
- \( NUMTRIP \): Number of trips to the site

The total cost of the installation vessel is specified by the daily rate of the installation vessel and the total time it needs to be leased. The total cost is derived through equation 26.

\[ TDC = SDR + VDR \]  

- \( TDC \): total daily cost
- \( VDR \): vessel day rate
- \( SDR \): spread day rate.
Finally the total cost of installation can be determined using equation 27. The total installation cost is a function of the installation time and total daily cost over 24 hours.

\[ \text{COST} = \frac{\text{INTIME}}{24} \times \text{TDC} \quad (\text{Kaiser & Snyder, 2012}). \]  

(27)

<table>
<thead>
<tr>
<th>Vessel type</th>
<th>Speed (kn)</th>
<th>Foundation capacity</th>
<th>Turbine capacity</th>
<th>Expected day rate ($/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lifeboat</td>
<td>4–6</td>
<td>0</td>
<td>1–2</td>
<td>35,400</td>
</tr>
<tr>
<td>JU barge</td>
<td>4–8</td>
<td>2–4</td>
<td>2–6</td>
<td>64,200</td>
</tr>
<tr>
<td>SPIV</td>
<td>8–12</td>
<td>4–8</td>
<td>6–8</td>
<td>134,300</td>
</tr>
</tbody>
</table>

Forecasting the cost of installing inner-array cables and export cables is achieved using the same methodology as for foundation and turbine installation. Inner-array cables installation cost is specified by the vessel day rate and required leasing time. The required vessel leasing time is calculated through the equation 28 (Kaiser & Snyder, 2012).

\[ \text{ARRAYTIME} = \frac{\text{ARRAYLENGTH}}{\text{ARRAYRATE}} \quad (28) \]

- ARRAYTIME: Time to install inner array cables
- ARRAYLEGHT: Cable length
- ARRAYRATE: Cable installation time (km/day)

The inner-array cable length can be calculated through various empirical relations. This study will utilize the farm capacity as a factor.

\[ \text{ARRAYLENGTH} = 0,00067(FC)^2 + 14,6 \quad (29) \]

- FC: Farm capacity
The cost of export cables is a function of the vessel day rate and the installation time.

\[ EXPORTCOST = EXPORTTIME \times EXPORTTD\text{DR} \]  \hspace{1cm} (30)

- \( EXPORTCOST \): Export cable installation cost
- \( EXPORTTIME \): Installation time
- \( EXPORTTD\text{DR} \): Vessel day rate

The export time is determined by the cable length and cable installation rate.

\[ EXPORTTIME = \frac{EXPORTLENGTH}{EPORTRATE} \]  \hspace{1cm} (31)

- \( EXPORTTIME \): Export time
- \( EXPORTLENGTH \): Cable length (km)
- Installation rate (km/day) (Kaiser & Snyder, 2012).

Substation installation is usually characterized by a jacket foundation that will be barged to the site. It is then put into place using a heavy-lift vessel. The jacket foundation uses a pile driving method to secure the substation into the sea bed. The time it takes to install the substation depends on a number of different factors including, depth, pile size, soil type and number of piles. A topside installation usually takes approximately three days (Kaiser & Snyder, 2012).

Scour protection will be installed by a barge. The timespan of this process depends on the amount of rocks and distance to site. It can be calculated through equation 32.

\[ TSR = SPU \times NUMUNIT \]  \hspace{1cm} (32)

- TSR: total tonnage of scour needed
• SPU: total scour per unit
• NUMUNIT: number of units

The number of trips is determined by the total scour requirements divided by the vessel capacity. Equation 33 is a function of total scour protection needed and vessel capacity.

\[
SCOURNUMTRIP = \frac{TSR}{SCOURVC}
\]

- \(SCOURNUMTRIP\): Number of trips required
- TSR: Total tonnage of scour needed
- SCOURVC: Vessel capacity (Kaiser & Snyder, 2012).

### Table 11 Number of export cables and substations required by distance to shore and generation capacity.

<table>
<thead>
<tr>
<th>Capacity (MW) Note:</th>
<th>&lt;100</th>
<th>100–200</th>
<th>200–300</th>
<th>&gt;300</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distance(km)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Export cables</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≤10</td>
<td>2*</td>
<td>1–3*</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>11–20</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>21–30</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>&gt;30</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Substations</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≤10</td>
<td>0</td>
<td>0–1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>11–20</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>21–30</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>&gt;30</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
</tbody>
</table>

### 2.4 REFERENCE CLASS FORECASTING METHODS

Kahneman and Tversky (1979) first published the theoretical and methodological foundation for reference class forecasting. The authors conclude that bias decisions are often systematic and predicable and shared by experts within a field of knowledge. Furthermore, human decisions are often optimistic due to optimism bias and strategic
misrepresentation. As a result, CAPEX is at risk of being underestimated and profits overestimated. The authors coined the term “planning fallacy” when managers are using an inside view as a forecasting method. They argue that “The analysts should therefore make every effort to frame the forecasting problem so as to facilitate utilizing all the distributional information that is available”. Flyvbjerg & Techn (2006) considers this finding one of the most important in terms of increasing correctness in forecasting methods. The process of using distributional information from other projects is referred to as the outside view. Reference class forecasting is based on the outside view in planning management.

Reference class forecasting is based on Daniel Kahneman theories concerning decision marking under uncertainty which led to the Nobel Prize in Economics 2002. Flyvbjerg & Techn (2006) define the reference class forecasting as an outside view approach. The outside view on a specific project is built upon data from a reference class of analogous projects. The authors state that the outside view can be applied onto number of different projects, including construction projects, power plants, dams, water projects, IT systems, oil and gas projects, aerospace projects and production plants.

The art of cost forecasting is a complex process which can involve a number of expert opinions. Experts may use knowledge from past projects or use mathematical models. Moreover, experts will frequently deliver a best guess in the method of forecasting future costs. Thus, forecasting CAPEX can involve a component of judgment, perception and educated guesswork (Kahneman & Tversky, 1979).

There are two types of data available for forecasters, singular and distributional. Singular information is referred to as information about a specific case, e.g. the development of an offshore wind farm. Distributional information is stated as the distribution of outcomes for similar projects, e.g. cost overruns for offshore wind power projects in the European Union. Planning fallacy is a result of neglecting the distributional information
and focusing too much on singular information. This approach is likely to generate cost underestimations (Kahneman & Tversky, 1979).

Flyvbjerg & Techn (2006) present a reference class approach to better forecast project costs. The authors quote the American Planning Association (APA) by stating that; "APA encourages planners to use reference class forecasting in addition to traditional methods as a way to improve accuracy. The reference class forecasting method is beneficial for non-routine projects ... Planners should never rely solely on civil engineering technology as a way to generate project forecasts". Reference class forecasting is based on a three-stage approach. In addition, two additional steps are user-selectable to further enhance the outcome. The five stages are as follows:

I. **Select a reference class.** Identification of an applicable reference class of prior projects. The class needs to be within the spectrum scope but wide enough to be statistically meaningful. Hence, creating a reference class for road constructions will be less time consuming than creating a reference class for a new technology. If the reference class approach is applied on a new technology, an extensive analysis of different variables needs to be performed in order to make reference class truly comparable.

II. **Assess the distribution of outcomes.** Creation of a probability distribution of the reference class. The data used needs to be statistically meaningful and trustworthy in order to get legitimate results. This includes different variables e.g. cost overruns, total costs and unit costs. The empirical data will be arranged in a cumulative distribution graph showing extremes, median, variance, standard deviation and any cluster.

III. **Make an intuitive prediction of your project’s position in the distribution.** The examined project will be compared with the reference class distribution. Based on singular information and specific conditions of a project, the forecaster will predict where the project is most likely to end on the
distribution line. The process of predicting costs using singular information can be established upon mathematical modeling or expert judgment.

IV. *Assess the reliability of your prediction.* Estimate the correlation between the forecast and outcome of a project, stated as a coefficient between zero and one. This is achieved by estimating the initial budget and then by comparing it with the cost of a project.

V. *Correct the intuitive estimates.* The initiative prediction will likely be exposed to bias which results in a too optimistic outcome. It is therefore necessary to adjust the result in step three. This is achieved by regressing the estimate towards the average base of the correlation coefficient. The regressed estimate is calculated through the equation in equation 34 (Kahneman, Tversky, 1977).

\[
C = C_{ar} + r_{xy}(C_e - C_{ar})
\]  

- \(C\) : cost  
- \(C_{ar}\) : Average reference cost  
- \(r_{xy}\) : correlation coefficient  
- \(C_e\) : estimated construction cost

2.4.1 REFERENCE CLASS FORECASTING IN WIND POWER DEVELOPMENT

Kaiser & Snyder (2012) analyze the possible cost of offshore wind farms in the U.S using a reference class approach. The authors use a regression model of normalized capital costs to examine CAPEX for offshore wind farms. Equation 35 was used to plot Figure 3, Figure 4, Figure 5 and Figure 6.
Kaiser & Snyder (2012) investigate factors affecting the capital cost of offshore wind power development. The authors normalize and adjust CAPEX to present values. Their analysis shows that capital cost of wind power development has increased from 2.2 million $/MW to over 4 million $/MW during the time period 2000 – 2014. Moreover, capital cost increases with installed capacity. This is opposite to what industry observers forecasted. The main impression has been that the cost per MW would decrease due to economics of scale and the learning factor. Nonetheless, costs increase as a result of the development of wind farms in deeper waters, further from shore and fluctuating commodity prices.

A tightening in the credit markets occurred as a result of the economic recession. This impacted the wind industry with lesser possibly to attract venture capital. The projects that did receive financial support encountered lower demands on turbines. This should decrease the capital cost of wind turbines (Kaiser & Snyder, 2012).

Kaiser & Snyder (2012) express that commodity prices have a vital role in determining the cost of a wind farm. Copper is used in cables, transformers and electrical equipment and accounts for 3% of CAPEX. Steel is used in the creation of the tower and nacelle. The cost of steel stands for 12% of the total CAPEX of a wind farm. In addition, oil, coal and natural gas will both have a positive and a negative effect on wind turbine CAPEX.
Wind farms are a complex engineering project, which is defined as “high cost, technology intensive, customized capital goods, systems, networks, control units, software packages, constructs and services” (Koch & Søndergaard, 2010). Complex engineering projects are often performed associated with a number of risks and uncertainties. This makes it difficult to implement a project budget. As a result, cost underestimations have become a global issue for big engineering projects. The issues seem to be optimism bias and strategic distortion. Optimism bias occur when planners underestimate the time and cost of a project. Strategic distortion happens as a result of organizational and political pressure. Decision makers create optimistic budgets in order to sell or buy complex engineering projects.

In order to understand the complex nature of an offshore wind farm, a cost breakdown structure needs to be performed. Table 12 shows the cost breakdown for two Danish wind farms.

<table>
<thead>
<tr>
<th>Wind farm component</th>
<th>Cost Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbines incl. transport and erection</td>
<td>49%</td>
</tr>
<tr>
<td>Foundations</td>
<td>21%</td>
</tr>
<tr>
<td>Substation and export cable</td>
<td>16%</td>
</tr>
<tr>
<td>Internal grid cable</td>
<td>5%</td>
</tr>
<tr>
<td>Design Project Management</td>
<td>6%</td>
</tr>
<tr>
<td>Pre-analysis and other</td>
<td>3%</td>
</tr>
</tbody>
</table>

Koch & Søndergaard (2010) studies a reference class consisting of 26 offshore wind farms in Denmark, Finland, The Netherlands, Ireland, Italy, Sweden and the UK. These wind farms either have gravity or monopile foundation. The water depth varies from 2 to 20 meters and turbines sizes are between 2-3MW. The size of the wind farms are within the spectrum of 10MW to 500MW. Continuing the reference class forecasting, the London Array wind farm was defined as the project to be analyzed. This narrowed down the reference class to nine wind farms in the UK and Ireland. The project shows a mean
cost of million 2.257€/MW with a cost overrun lying within the spectrum of 0% to 38% with a mean cost overrun of 11.5%. Since the reference group only consists of nine wind farms, a distribution curve will not be statistically significant. The authors choose to analyze the cost and time frame of the London Array project by determining how the cost contingency level should increase in order to reduce the risk of a cost overrun. The authors recommend a cost contingency uplift by 15% and an extended time frame by 30% to reduce the risk of a time overrun for the London Array wind farm.

2.5 CONTINGENCIES

Contingency in construction management refers to the budget account which target unexpected costs during the project. In this thesis, cost contingency is defined as the amount of money that needs to be added to the base estimate in order to account for cost uncertainties. The account does not take scope changes into consideration. Moreover, a contingency budget does not account for unexpected situations beyond management's control (Burroughs & Juntima, 2004).

The most common contingency method is to set aside a percentage of the estimated cost to cover for known and unknown expenditures. Another common method for contingency allowance is to set aside contingencies for each account within a cost breakdown. In addition, more advanced statistical methods have been developed in order to increase the accuracy in cost contingency budgeting. Table 13 presents recommended contingency practices outlined by the Association for the Advancement of Cost Engineering International and Electric Power Research Institute (Touran 2003).

<table>
<thead>
<tr>
<th>AACEI Project stage</th>
<th>AACEI suggested contingency</th>
<th>EPRI suggested contingency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Screening</td>
<td>50%</td>
<td>-</td>
</tr>
<tr>
<td>Feasibility study</td>
<td>30%</td>
<td>30-50%</td>
</tr>
<tr>
<td>Authorization</td>
<td>20%</td>
<td>15-30%</td>
</tr>
</tbody>
</table>

Table 13 Suggested contingency comparison between Association for the Advancement of Cost Engineering International and Electric Power Research Institute. Source Rothwell (2005)
Risk and uncertainties is the dominant force causing cost overruns if not handled during project development. Cost estimations needs to be revised during each stage of a project. Advancement of Cost Engineering International (WSDOT) has developed a cost classification system with regard to each stage of an engineering project. The system is designed to reduce the contingency level as the project proceeds. Figure 8 illustrates how the contingency budget develops during a project. A known but not quantified cost refers to a cost which will occur but cannot be quantified. Unrecognized costs, also known as unforeseen need to be accounted for but are not generally included in the budget. Thus, a project budget is a dynamic document which needs to be revised and audited during the time span of a project (Molenaar et al, 2010).

<table>
<thead>
<tr>
<th>Tender</th>
<th>15%</th>
<th>10-20%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bid</td>
<td>5%</td>
<td>5-10%</td>
</tr>
</tbody>
</table>

Figure 8 Contingency levels for different stages of a project. Source: Molenaar et al 2010
2.6 CONCLUSIONS

B-1. What does the research trends say about cost forecasting?

The research community recommends a number of different methods in cost forecasting. Cost estimations using regression models have been discussed. In addition, cost equations with respect to the amount of resources needed have been presented. These methods are coined as the inside view. The inside view focus on site specific conditions in order to produce a cost estimate for a project. In contrast to the inside view, the outside view has been described in terms of reference class forecasting. Reference class forecasting aims to reduce optimism bias and strategic misrepresentation in investment decisions by adjusting the cost estimate cost using a statistical distribution.

B-2. How does the latest research explain cost overruns?

The research community explains cost overruns by mainly mentioning optimism bias and strategic misrepresentation. Optimism bias refers to the inability to examine benefits and disadvantages in an objective way. Strategic misrepresentation describes cost overruns by claiming that organizational and political stress forces decision makers to brand investment in an overly optimistic way.
CHAPTER 3. METHODOLOGY AND DATA

Chapter 3 will orient the reader in research design and applicable methodology. Data samples will be presented and statistical findings are illustrated. Moreover, a description of utilized methods will be described.

The following sub-research question will be answered in the following chapter.

- C-1. How can CAPEX in offshore wind power projects be estimated using a cost calculation approach?
- C-2. How can CAPEX in offshore wind power projects be forecasted using the reference class forecasting method?

3.1 DESCRIPTION OF THE METHODOLOGICAL FRAMEWORK

3.1.1 RESEARCH DESIGN

This section aims to describe two different research methodologies; quantitative and qualitative research. Quantitative research has long been the primary methodology in engineering and technical sciences. Nevertheless, each method serves a purpose and should be analyzed in accordance to the specific context of a dissertation (Borrego et al, 2009). A description of each method will be presented in the following paragraphs. Finally, a justification of research method choice will be illustrated.
The quantitative research methodology is a deductive approach in which a hypothesis and or a theory validate the purpose, the variables and the research question. The research question or hypothesis will steer how data will be collected. Furthermore, the deductive approach determines how the data will be statistically analyzed. Quantitative research aims to calculate the findings onto a larger population through an objective process. Entire data sets or data samples are used to make generalized assumptions. The results are interpreted and statistics are derived to see whether the results can be generalized for a larger population (Borrego et al, 2009).

There are several ways in which statistical result can be derived. One method uses descriptive statistics to describe the situation without addressing the relationship between different variables. Descriptive statistics are typically used in new scientific fields where there are little or no known knowledge. Another statistical method examines the relationship between various indicators. Pre-existing knowledge is used to create hypotheses. The hypothesis examines the relationship that possibly exists between different variables. The hypothesis is usually described as a research question. To answer the research question, data are collected and then analyzed. Finally, the hypothesis is either accepted or rejected based on the analysis. A third method used in quantitative research is the explicit use of theory. This method is based on the same type of approach as when studying the relationship between various indicators. However, the theory is much more dominant in this approach and permeates the research process. This approach is typically used when examining the relationship between different variables. The analysis is justified by the theory in use. One well known approach using theory is the use of a regression analysis to study the behavior of a data sample (Borrego et al, 2009).

The qualitative research methodology is based on a post-positivist perspective. The research is based on empirical data like surveys, interviews, focus groups, conversations
and observations. The research question aims to answer questions like “what is happening?” and “why is it happening?” (Borrego et al, 2009).

There are different ways to perform qualitative research. One way is to explain reality through a theoretical perspective. This method aims to explain a specific epistemology. Qualitative research uses an inductive approach when data is analyzed. Inductive researchers examine data without preconceptions. This shapes the result in a different form compared with a hypothesis approach. To minimize bias results, a researcher needs to present a transparent report with detailed information on how the data sets were gathered and how it was analyzed. This is conducted using a data validation technique. Qualitative research usually focuses on a specific context within a larger population. The aim is not to generalize the data to the whole population but instead fully understand the situation in the specific context (Borrego et al, 2009).

This thesis is based on a quantitative research methodology. Moreover, a deductive research approach is applied. The author focuses on the explicit theory. This approach is justified by the nature of the study. Forecasting CAPEX is based on a two-step approach using the inside view to calculate the total investment cost of an offshore wind farm and then adjusting the cost contingency budget using the outside view. Empirical data will be statistically derived and analyzed in accordance with the research question.

### 3.1.2 RESEARCH RELIABILITY

Research reliability refers to the consistency in the measurements. If the data is not expected to change over time, statistical tests should be somewhat similar over time. If this is not the case, performed research adds little value to the scientific community. There are two different types of common errors in data measurements. Firstly, measurement errors can interfere with the research reliability. This is a random error which can change over time. Secondly, bias errors are a systematic mistake. These errors will therefore always be present.
3.1.3 DESCRIPTION OF DATA SOURCES
Scientific research usually evolves from previous research. Research data can be gathered from a number of different source levels. Depending on the scope and type of research, choosing the correct data source is a fundamental process in scientific research (Cunningham et al, 2012). Three different types of bibliographic sources will be presented. Then, a justification of chosen sources will be described.

A researcher needs to determine which parameters can affect the reliability of the data. A researcher can increase the reliability of the data in several ways. One common method is to increase the amount of used sources.

Third level sources, also known as tertiary bibliographic sources offer the most general review of a topic. They usually occur in textbooks and text magazines. This type of source will give you a broad picture of a research topic. However, it is not recommended to use a third level source in academic papers. This is due to the limited peer reviewing of the references (Cunningham et al, 2012).

Secondary bibliographic sources refer to comprehensive reviews written by experts. They tend to be more in depth than third level sources. However, this level has its limitations. There seems to be a lag between the primary source and comments in the form of a secondary reference. In addition, secondary sources are usually less focused than primary references. One type of secondary source is a literature review in academic papers (Cunningham et al, 2012).

Primary bibliographic sources are research papers in published scientific journals. Primary sources have the highest legitimacy since they have been peer reviewed by a
number of scientists in the same field. The peer review process aims to increase the validity of papers (Cunningham et al, 2012).

This thesis will gather information from secondary and primary bibliographic sources. The author aims to gather as much information from primary references. Nonetheless, secondary sources in the form of a literature review will be a useful complement in some parts of the thesis. The literature review will have a descriptive approach which will describe the applicable theory and relate it to the problem statement.

3.2 PRESENTATION OF DATA SOURCES

Wind power cost data was gathered from the article “Construction Cost Overruns and Electricity Infrastructure: An Unavoidable Risk” by Sovacool et al (2014). The article was published in May 2014, in the scientific database “The Electricity journal”. The article has been peer reviewed which creates legitimacy to the source. Nonetheless, one must be critical to data which is not gathered from the original source. The author is aware of this issue but accepts the risk with bias or changed data.

A total of 22 offshore wind farms are in the sample. Cost values are inflated to 2012 years net present value. Table 14 shows a statistical overview of the wind farms. Capacity, budget and actual cost are presented. Figure 9 shows a plot of the statistical data.
<table>
<thead>
<tr>
<th>Name</th>
<th>Location</th>
<th>Capacity (MW)</th>
<th>Initial Budget Million €</th>
<th>Actual Cost Million €</th>
<th>Cost overrun Million €</th>
<th>Cost overrun (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sheringham Shoal</td>
<td>United Kingdom</td>
<td>317</td>
<td>914</td>
<td>1319</td>
<td>405,3</td>
<td>44%</td>
</tr>
<tr>
<td>Barrows</td>
<td>UK/Ireland</td>
<td>90</td>
<td>93</td>
<td>150</td>
<td>57,0</td>
<td>38%</td>
</tr>
<tr>
<td>Centrica Lincs</td>
<td>United Kingdom</td>
<td>270</td>
<td>933</td>
<td>1205</td>
<td>271,0</td>
<td>29%</td>
</tr>
<tr>
<td>Burbo Banks</td>
<td>UK/Ireland</td>
<td>90</td>
<td>101</td>
<td>139</td>
<td>38,5</td>
<td>28%</td>
</tr>
<tr>
<td>Horns Rev I</td>
<td>Denmark</td>
<td>160</td>
<td>238</td>
<td>289</td>
<td>50,8</td>
<td>21%</td>
</tr>
<tr>
<td>Lillgrund</td>
<td>Sweden</td>
<td>110</td>
<td>174</td>
<td>205</td>
<td>30,8</td>
<td>18%</td>
</tr>
<tr>
<td>Lynn and inner Dowsing</td>
<td>UK/Ireland</td>
<td>194</td>
<td>341</td>
<td>392</td>
<td>50,8</td>
<td>13%</td>
</tr>
<tr>
<td>Robin</td>
<td>UK/Ireland</td>
<td>180</td>
<td>320</td>
<td>347</td>
<td>27,7</td>
<td>8%</td>
</tr>
<tr>
<td>Middelgrunden</td>
<td>Denmark</td>
<td>40</td>
<td>48</td>
<td>51</td>
<td>3,1</td>
<td>7%</td>
</tr>
<tr>
<td>Scroby Sands</td>
<td>UK/Ireland</td>
<td>60</td>
<td>78</td>
<td>86</td>
<td>8,5</td>
<td>5%</td>
</tr>
<tr>
<td>Rhyll</td>
<td>UK/Ireland</td>
<td>90</td>
<td>175</td>
<td>183</td>
<td>8,3</td>
<td>5%</td>
</tr>
<tr>
<td>North Hoyle</td>
<td>UK/Ireland</td>
<td>60</td>
<td>85</td>
<td>89</td>
<td>3,9</td>
<td>4%</td>
</tr>
<tr>
<td>Thanet</td>
<td>United Kingdom</td>
<td>300</td>
<td>938</td>
<td>975</td>
<td>37,5</td>
<td>4%</td>
</tr>
<tr>
<td>Kentish Flats</td>
<td>UK/Ireland</td>
<td>90</td>
<td>116</td>
<td>119</td>
<td>3,1</td>
<td>3%</td>
</tr>
<tr>
<td>London Array</td>
<td>United Kingdom</td>
<td>630</td>
<td>2250</td>
<td>2289</td>
<td>39,0</td>
<td>2%</td>
</tr>
<tr>
<td>Arklow Bank</td>
<td>UK/Ireland</td>
<td>25</td>
<td>32</td>
<td>32</td>
<td>0,0</td>
<td>0%</td>
</tr>
<tr>
<td>Nysted</td>
<td>Denmark</td>
<td>166</td>
<td>280</td>
<td>280</td>
<td>0,0</td>
<td>0%</td>
</tr>
<tr>
<td>Horns Rev II</td>
<td>Denmark</td>
<td>209</td>
<td>489</td>
<td>489</td>
<td>0,0</td>
<td>0%</td>
</tr>
<tr>
<td>Danish Anholt</td>
<td>Denmark</td>
<td>400</td>
<td>1371</td>
<td>1371</td>
<td>0,0</td>
<td>0%</td>
</tr>
<tr>
<td>Rødsand II</td>
<td>Denmark</td>
<td>207</td>
<td>467</td>
<td>464</td>
<td>-3,8</td>
<td>-1%</td>
</tr>
<tr>
<td>Samsø</td>
<td>Denmark</td>
<td>23</td>
<td>34</td>
<td>33</td>
<td>-1,2</td>
<td>-3%</td>
</tr>
<tr>
<td>Walney</td>
<td>United Kingdom</td>
<td>367</td>
<td>1342</td>
<td>1220</td>
<td>-122,0</td>
<td>-9%</td>
</tr>
</tbody>
</table>
3.3 DESCRIPTION OF MODELS

This section aims to describe the models used to generate mathematical results. Three different models will be used. The first model is designed to estimate investment cost for offshore wind power. The second model aims to forecast installation costs for an offshore wind farm. The third model is the reference class forecasting method. This model will adjust the CAPEX to the selected reference class. The combination of three models aims to reduce the influence of optimism bias and strategic representation in the process of forecasting CAPEX for offshore wind power.
3.3.1 CALCULATING THE INVESTMENT COST
Dicorato et al (2011) demonstrates how to calculate investment cost for offshore wind power. A hypothetical 150MW wind farm containing of 3MW turbines will be used to calculate the investment cost. Turbines will have a rotor diameter of 90m and a hub height of 75m. The results will be described as a cost breakdown, which will include various sea depths and distance to the mainland. Figure 10 shows an overview of the 150MW offshore wind farm. Cost calculations will be defined in accordance with Figure 10.

<table>
<thead>
<tr>
<th>150 MW offshore wind farm</th>
</tr>
</thead>
<tbody>
<tr>
<td>dwf [km]</td>
</tr>
<tr>
<td>D [m]</td>
</tr>
</tbody>
</table>

Figure 10 Parameters for a 150 MW offshore wind farm. Source: Kaiser et al (2012)

3.3.2 INSTALLATION COST CALCULATIONS
Calculating the installation cost will be based on the work of Kaiser et al (2012). The spacing between each turbine is defined as 500m. Distance between each row is set to 1 km. Parameters from Figure 10 will be used to calculate the installation cost for different wind farm scenarios.

3.3.3 REFERENCE CLASS FORECASTING
The reference class forecasting method is designed to adjust for optimism bias and strategic misrepresentation. The author aims to utilize the same method as Flyvbjerg &
Techn (2006) apply in article “From Nobel Prize to Project Management: Getting Risks Right”. In order to reduce optimism bias and strategic misrepresentation in cost calculations, the following methodology will be exploited:

**Select a reference class.** Empirical data has been gathered for 22 offshore wind farms within the European Union. This is approximately 30% of all offshore wind farms in the region.

**Assess the distribution of outcomes.** A probability distribution of the reference class is designed. The data that is used needs to be statistically meaningful and trustworthy in order to get a legitimate result. This includes different variables e.g. cost overruns, total costs and unit costs. The empirical data will be displayed in a cumulative distribution graph showing extremes, median, variance, standard deviation and cluster. Table 15 shows a statistical summary of the empirical data set.

<table>
<thead>
<tr>
<th>Initial Budget Million €</th>
<th>Actual Cost Million €</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean</td>
<td>Mean</td>
</tr>
<tr>
<td>492</td>
<td>533</td>
</tr>
<tr>
<td>Standard Error</td>
<td>Standard Error</td>
</tr>
<tr>
<td>122</td>
<td>128</td>
</tr>
<tr>
<td>Median</td>
<td>Median</td>
</tr>
<tr>
<td>259</td>
<td>284</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>Standard Deviation</td>
</tr>
<tr>
<td>574</td>
<td>599</td>
</tr>
<tr>
<td>Sample Variance</td>
<td>Sample Variance</td>
</tr>
<tr>
<td>330025</td>
<td>359036</td>
</tr>
<tr>
<td>Range</td>
<td>Range</td>
</tr>
<tr>
<td>2217</td>
<td>2256</td>
</tr>
<tr>
<td>Minimum</td>
<td>Minimum</td>
</tr>
<tr>
<td>32</td>
<td>32</td>
</tr>
<tr>
<td>Maximum</td>
<td>Maximum</td>
</tr>
<tr>
<td>2250</td>
<td>2289</td>
</tr>
<tr>
<td>Count</td>
<td>Count</td>
</tr>
<tr>
<td>22</td>
<td>22</td>
</tr>
</tbody>
</table>

*Table 15 Key statistics for reference class 1, offshore wind farms, Source: Own processing*

**Make an intuitive prediction of your project’s position in the distribution.** The examined project will be compared with the reference class distribution. This will create a more realistic forecast of the project. Based on one’s experience and knowledge of a project, the project manager needs to predict where the project is most likely to end on the
distribution line. The prediction will then be adjusted according to the bias uplift (Flyvbjerg & Techn, 2006).

3.4 CONCLUSIONS

C-1. How can CAPEX in offshore wind power projects be estimated using a cost calculation approach?
CAPEX in offshore wind power projects can be forecasted using a two stage approach. Firstly, investment costs are estimated using regression equations. Secondly, installation costs are forecasted using site specific facts. The combination results in a cost estimate which can be used in the screening and feasibility stage of an offshore wind power project.

C-2. How can CAPEX in offshore wind power projects be forecasted using the reference class forecasting method?

The reference class forecasting method is suitable for producing an estimate for bias uplift. The method takes historical data into consideration when formulating the necessary level of contingency in the project budget. By adjusting the contingency level to the acceptable risk of cost overruns, the possibility of a budget exceedance will decrease.
CHAPTER 4. APPLICATION OF THE METHODOLOGY AND RESULTS

Chapter 4 will demonstrate how cost calculations and the selected reference class can be combined in order to mitigate the risk of a cost overrun. Outcomes from 22 offshore wind farms will be presented in a cumulative frequency graph. In addition, the required uplift will be illustrated.

The following sub-research question will be answered in this chapter:

- D-1. How can a cost calculation approach and reference class forecasting model be combined to estimate CAPEX in offshore wind power projects?

4.1 INVESTMENT COST DERIVATION

Section 4.1 aims to announce investment costs associated with the development of an offshore wind farm. Table 16 shows the results for eight different scenarios. The investment costs are ranging from a total investment cost of 276 377 000€ to 301 805 000€. The main cost drivers are turbines, foundations and transformers. Shunt regulation devices are not included, since it depends on local regulations set by the transmission system operator.
Table 16 Cost of a 150MW offshore wind farm, installation cost not included.

<table>
<thead>
<tr>
<th>Turbine, BoP &amp; development cost (K€)</th>
<th>3</th>
<th>3</th>
<th>5</th>
<th>5</th>
<th>5</th>
<th>10</th>
<th>10</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>dwf [km]</td>
<td>10</td>
<td>15</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>15</td>
<td>20</td>
<td>25</td>
</tr>
<tr>
<td>D [m]</td>
<td>10</td>
<td>15</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>15</td>
<td>20</td>
<td>25</td>
</tr>
<tr>
<td>Cost foundation</td>
<td>51 992 €</td>
<td>56 991 €</td>
<td>51 992 €</td>
<td>56 991 €</td>
<td>61 990 €</td>
<td>56 991 €</td>
<td>61 990 €</td>
<td>66 989 €</td>
</tr>
<tr>
<td>Cost collection system</td>
<td>20 454 €</td>
<td>20 687 €</td>
<td>20 454 €</td>
<td>20 687 €</td>
<td>20 092 €</td>
<td>20 687 €</td>
<td>20 092 €</td>
<td>21 154 €</td>
</tr>
<tr>
<td>Cost integration system</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
<td>21 656 €</td>
</tr>
<tr>
<td>Cost transformer</td>
<td>28 220 €</td>
<td>31 000 €</td>
<td>31 000 €</td>
<td>31 000 €</td>
<td>37 950 €</td>
<td>37 950 €</td>
<td>37 950 €</td>
<td>37 950 €</td>
</tr>
<tr>
<td>Cost regulation</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
<td>- €</td>
</tr>
<tr>
<td>Cost SCADA</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
<td>3 750 €</td>
</tr>
<tr>
<td>Cost plant</td>
<td>269 357 €</td>
<td>274 589 €</td>
<td>272 137 €</td>
<td>277 369 €</td>
<td>263 773 €</td>
<td>284 319 €</td>
<td>270 723 €</td>
<td>294 785 €</td>
</tr>
<tr>
<td>Cost development</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
<td>7 020 €</td>
</tr>
<tr>
<td>Cost investment</td>
<td>276 377 €</td>
<td>281 609 €</td>
<td>279 157 €</td>
<td>284 389 €</td>
<td>288 793 €</td>
<td>291 339 €</td>
<td>295 743 €</td>
<td>301 805 €</td>
</tr>
</tbody>
</table>

4.2 INSTALLATION COST DERIVATION

Section 4.2 will illustrate installation costs related to offshore wind power development. Three different scenarios are presented in Table 17. Each scenario represents the same distance to shore as for the investment costs. The cost installation spectrum ranges from 62 420 000€ to 64 400 000€.

Table 17 Installation cost for a 150MW farm. Source: Own processing

<table>
<thead>
<tr>
<th>Installation Cost (K€)</th>
<th>3km</th>
<th>5km</th>
<th>10km</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total WTG installation cost</td>
<td>20 590 €</td>
<td>20 590 €</td>
<td>20 740 €</td>
</tr>
<tr>
<td>Total Foundation installation cost</td>
<td>23 540 €</td>
<td>23 550 €</td>
<td>23 580 €</td>
</tr>
<tr>
<td>Total cable installation cost</td>
<td>7 620 €</td>
<td>7 980 €</td>
<td>9 410 €</td>
</tr>
<tr>
<td>Total Mobilization &amp; Sea-fastening cost</td>
<td>10 670 €</td>
<td>10 670 €</td>
<td>10 670 €</td>
</tr>
<tr>
<td>TOTAL INSTALLATION COST</td>
<td>62 420 €</td>
<td>62 790 €</td>
<td>64 400 €</td>
</tr>
</tbody>
</table>
4.3 REFERENCE CLASS 1, OFFSHORE WIND FARMS

Figure 11 illustrates the reference class consisting of 22 data samples. Cost overruns can be found in the spectrum of -9% to 44%. The plot shows that 32% of offshore wind farms projects have a maximum cost overrun by 0%. Furthermore, 91% of the projects reference class 1 has a maximum cost overrun of 29%.

Figure 11 cumulative frequency distribution for reference class one. Source: Own processing
4.4 CONTINGENCY UPLIFT

Section 4.4 will describe the results for the required bias uplift. The plot will be used to add the suitable cost contingency uplift with regard to the acceptable risk tolerance. Depending on the project stage, the cost contingency should be adjusted to better fit the acceptable risk level.

Table 20 illustrates the required cost contingency budget with respect to acceptable risk level. The maximum acceptable risk level is defined to 50%. Derivations are based upon
the investments and installation costs for a 150 MW offshore wind farm. The normalized capital cost ranges between 2.58 million € and 3.58 million €.

| Table 18 CAPEX for 150MW offshore wind farm including contingency budget with respect to acceptable risk of cost overrun Source: Own processing |
|---|---|---|---|---|---|---|---|---|---|
| | dwf [km] | 3 | 3 | 5 | 5 | 5 | 10 | 10 | 10 |
| | D [m] | 10 | 15 | 10 | 15 | 20 | 15 | 20 | 25 |
| Total cost of wind farm excluding contingency account (€K) | 338797 € | 344029 € | 341947 € | 347179 € | 333583 € | 355739 € | 342143 € | 366205 € |
| Acceptable risk of cost overrun | Contingency account (€K) | 0% | 149071 € | 151373 € | 150457 € | 152759 € | 146777 € | 156525 € | 150543 € | 161130 € |
| | 10% | 98251 € | 99768 € | 99165 € | 100682 € | 96739 € | 103164 € | 99221 € | 106199 € |
| | 20% | 71147 € | 72246 € | 71809 € | 72908 € | 71147 € | 74705 € | 71850 € | 76903 € |
| | 30% | 44044 € | 44724 € | 44453 € | 45133 € | 43366 € | 46246 € | 44479 € | 47607 € |
| | 40% | 23716 € | 24082 € | 23936 € | 24303 € | 23351 € | 24902 € | 23950 € | 25634 € |
| | 50% | 13552 € | 13761 € | 13678 € | 13887 € | 13343 € | 14230 € | 13686 € | 14648 € |

4.5 CONCLUSIONS

D-1. How can a cost calculation approach and reference class forecasting method be combined to estimate CAPEX in offshore wind power projects?

Cost calculations and the reference class forecasting method can be combined by adjusting the cost contingency budget in accordance with the required bias uplift. To mitigate the risk of cost overruns and a fractured budget, one should decide upon an acceptable risk level.
CHAPTER 5. DISCUSSION AND ANALYSIS

Chapter 5 aims to bring understanding to the results by analyzing the findings in chapter 4 within the context of the literature. Firstly, the cost estimation approach will be discussed. Secondly, the distribution of cost overruns and the required bias uplift will be analyzed.

The following sub-research question will be answered:

- F-1 Is reference class forecasting applicable in offshore wind power cost contingency budgeting?

Deriving investment cost using a regression model seems to generate a low cost estimate. According to the applied model, the investment cost will be in the scale of 1.84 million €/MW to 2.01 million €/MW. Adding the installation cost of approximately 0.42 million €/MW produces a total cost of between 2.26 million €/MW to 2.43 million €/MW depending on location of the wind farm. Compared with data from section (2.1), the cost estimate is located in the bottom range of CAPEX associated with offshore wind power development. These findings suggest that a cost contingency budget needs to be implemented in order to cover potential cost overruns.

Following the link between chapters, it can be concluded that reference class forecasting in offshore wind power projects have been scarcely used. From this knowledge, one can either make the assumption that reference class forecasting does not suit the context of wind power development or that the method is not known within the industry. The
findings in this thesis suggest option number two. A clarification of this will follow in the next paragraphs.

As seen in Figure 7, approximately 70% of offshore wind farms in the sample encounter cost overruns. This suggests that insufficient budgeting methods are used within the reference class. It should therefore be of interest for decision makers to apply reference class forecasting in the budgeting process.

Comparing the recommended cost contingency budget in Table 13 with the result from the cost contingency uplift in Figure 8 one can make the conclusion that the necessary risk of cost overrun should be in the range of 0-10%. This risk level suggests a cost contingency budget of 44% to 29% which is in line with AACEI & EPRI’s recommendations. According to Table 18, this would require a cost contingency budget from 1.07 million €/MW to 0.64 million €/MW.

Koch & Søndergaard (2000) recommend a budget uplift of 15% for the London Array offshore wind power project. Their findings are moderately lower than the results produced in this thesis. The comparison illustrates the importance of a relevant reference class. One can make the conclusion that Koch & Søndergaards (2000) reference class is narrower than the applied reference class in this thesis. For example, the authors only included projects located around the British Islands whereas a reference class consisting of projects in the European Union was chosen in this thesis. A more specific reference class is preferred due to the fact that costs should be somewhat similar with regard to parameters as size, distance to shore and age. However, one must be shed light on the fact that the London Array reference class only consists of nine offshore projects which reduce the reliability of the results.

The comparison between the results of Koch & Søndergaard (2000) and this thesis draws attention to the fact that the reference class needs to be chosen with great caution. A
number of different parameters should be included to minimize the risk of inaccurate contingency uplift. Nevertheless, one can argue that reference class forecasting is applicable in the offshore budgeting process.

When applying these findings to a 150MW wind farm, it is suggested that the cost contingency be budgeted between 96 and 160 million €. The amount is high from a business perspective. Nevertheless, the cost contingency percentage is well in line with recommended values. Figure 13 displays the cost contingency budget with respect to the level of risk acceptance.

Continuing the analysis, the total cost per MW including contingencies would be between 2.9 million €/MW and 3.5 million €/MW. These costs are well in line with the data from section (2.1). Hence, the author makes the conclusion that reference class forecasting is applicable in the context of offshore wind power development. However, this statement is only valid when models displayed in this thesis are applied.
Applying the cost forecasting methodology must be considered as a rough estimate of future costs. Nonetheless, the results suggest that the cost range is within the boundaries of most modern wind farms. The model introduces an element of experience in the cost forecasting process. This must be considered as a better approach than solely relying on subjective expert opinions.
CHAPTER 6. CONCLUSIONS

Chapter 6 aims to present the findings of this thesis. Conclusions will be based on a link between the literature review, methodology and results. In addition, recommendations for future research will be proposed.

The main research question will be answered in this chapter. The research question is as follows:

- A1. How can a cost contingency budget in wind power projects be estimated and modeled?

The following sub-research question will be answered:

- E-1. What recommendations can be made when forecasting CAPEX in offshore wind power projects?
- E-2. How can the reference class forecasting increase budget accuracies for offshore wind power projects?

The aim of this thesis is to create a model to estimate CAPEX in offshore wind power development. The author has combined two different models to approach this issue. Firstly, cost calculations has been performed using the inside view. Secondly, optimism bias and strategic misrepresentation in the context of wind power development has been reduced using reference class forecasting with respect to the outside view. The results suggest that a cost contingency budget can be modeled by merging an investment cost analysis, installation cost approach and reference class forecasting.
With regard to the combined model, results from the theoretical wind farm suggest that it is possible to apply both the inside and the outside view in the process of forecasting CAPEX. However, the author emphasizes that result in this thesis only serves as a guideline for professionals. The guideline can be applied in the screening or feasibility phase of a project. In later stages of a project, a more qualified model needs to be implemented.

The cost contingency uplift is located in the range of 44% to 4% if the acceptable of a cost overrun is defined to a maximum of 50%. This may or may not change if the number of projects in the reference class was increased. Nonetheless, decision makers within the wind power industry need to be aware of the risk of cost overruns. Implementing reference class forecasting will increase the chance of defining a more accurate amount of contingencies in the CAPEX budget.

The author underlines that reference class forecasting can be used in every stage of a project. In order to create a reference class with high statistical relevance, data needs to be gathered from multiple sources. This would increase the chance of determining a correct cost contingency budget. It is also possible to create a reference class for a specific turbine manufacturer. By narrowing down the reference class to better fit project characteristics, one should be able to better forecast CAPEX.

5.1 LIMITATIONS

Applying an inside view as well as an outside view when forecasting CAPEX for offshore wind power projects has its limitations. Equations used in the thesis are mainly based on regression models. With technology improvements and changes in the typical wind power scope, the regression models need to be updated to keep its validity. Furthermore, one needs to be aware of errors in the equations. Cost forecasting is not an exact science which will affect the estimate. It is therefore necessary to calculate
CAPEX using a sensitivity analysis to better understand the cost spectrum for a specific project.

It is also of importance to understand that reference class forecasting was officially published in 2004. During the time it has been available, only a scarce number of publications have been made. This may be a result of difficulties associated with obtaining cost data. Cost data is by its nature confidential which reduces transparency. One also needs to be aware of the fact that cost data differs between sources. This may be a result of different inflation methods or due to the fact that provided data is wrong. Bad data may increase the risk of incorrect forecasts.

The main implication of reference class forecasting is reducing optimism bias and strategic misrepresentation. Reference class forecasting will be a useful tool in terms of reducing optimism bias. However, strategic misrepresentation is a syndrome where conscious decisions are made to increase the chance of project approval. Hence, decision makers who deliberately aim to reduce the cost forecast will have little or no interest of implementing the method into their organization.

5.2 IMPLICATIONS FOR FUTURE RESEARCH

This research shows that reference class forecasting can be utilized together with normal cost estimation methods. However, this model is only applicable in the screening and feasibility stage of a project. To further increase cost forecasting in offshore wind power projects, research can be performed with respect to multiple reference classes. For example, gathering cost overrun data for every wind farm in the European Union would create more legit results. Moreover, with a bigger data set, contingency adjustments would be more adapted for a specific location.
With regard to the model, regression equations used in this thesis can be updated with respect to more recent projects. In addition, a budget analysis could be performed to better understand how cost drivers fluctuate during different stages of a project. This kind of research would be of big importance since it would allow decision makers to adjust budget forecasts during the project.

Reference class forecasting can also be applicable for a specific turbine component. If cost data for every component were gathered, a reference class model could be created using a full cost breakdown. This approach would be valuable in the context of wind power cost estimations.

5.3 REFLECTIONS

The author’s reflection can be described from a scientific and professional perspective. With regard to a scientific perspective, transparency is the motto of this thesis. The author will therefore emphasize the fact that only a limited number of sources were used when creating the model. This may or may not decrease the legitimacy of the thesis. Nonetheless, sources have been peer-reviewed which suggests that each applied model is legitimate on its own.

With respect to a professional perspective, the findings suggest that a cost contingency budget can be calculated using this model. However, each attempt of budget forecasting needs to be performed by experts. The model itself will not guarantee any mitigation of cost overruns.
REFERENCES


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Manwell et al (2009). WIND ENERGY EXPLAINED Theory, Design and Application. West Sussex: John Wiley & Sons Ltd


## Appendix (1) offshore CAPEX breakdown.

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<thead>
<tr>
<th>Development and consent</th>
<th>Wind turbine</th>
<th>Balance of Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>D0. Development and consent</td>
<td>T0. Wind turbine</td>
<td>B0. Balance of Plant</td>
</tr>
<tr>
<td>D1.1. Benthic environmental surveys</td>
<td>T1.1. Nacelle bedplate</td>
<td>B1.1. Export cable</td>
</tr>
<tr>
<td>D1.2. Pelagic environmental surveys</td>
<td>T1.2. Main bearing</td>
<td>B1.2. Array cable</td>
</tr>
<tr>
<td>D1.3. Ornithological environmental surveys</td>
<td>T1.3. Main shaft</td>
<td>B1.3. Cable protection</td>
</tr>
<tr>
<td>D1.4. Sea mammal environmental surveys</td>
<td>T1.4. Gearbox</td>
<td>B2. Turbine foundation</td>
</tr>
<tr>
<td>D1.5. Ornithological and mammal surveying craft</td>
<td>T1.5. Generator</td>
<td>B2.2. Transition piece</td>
</tr>
<tr>
<td>D1.6. Onshore environmental surveys</td>
<td>T1.6. Power take-off</td>
<td>B3. Offshore substation</td>
</tr>
<tr>
<td>D2. Coastal process surveys</td>
<td>T1.7. Control system</td>
<td>B3.1. Electrical system</td>
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<td>T1.8. Yaw system</td>
<td>B3.2. Facilities</td>
</tr>
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<td>D3.1. Met station structure</td>
<td>T1.9. Yaw bearing</td>
<td>B3.3. Structure</td>
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<td>D3.3. Met station auxiliary systems</td>
<td>T1.10. Nacelle auxiliary systems</td>
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<td>D3. Met station sensors</td>
<td>T1.11. Nacelle cover</td>
<td></td>
</tr>
<tr>
<td>D4. Sea bed surveys</td>
<td>T1.12. Small engineering components</td>
<td></td>
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<td>D4.1. Geophysical surveys</td>
<td>T1.13. Fasteners</td>
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<td>D4.2. Geophysical survey vessels (dayrate)</td>
<td>T1.14. CMS</td>
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<td>D4.3. Geotechnical surveys</td>
<td>T2. Rotor</td>
<td></td>
</tr>
<tr>
<td>D4.4. Geotechnical survey vessels</td>
<td>T2.1. Blades (price/blade)</td>
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<td>D5. Front end engineering and design studies</td>
<td>T2.2. Hub casting</td>
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</tr>
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<td>D6. Human impact studies</td>
<td>T2.3. Blade bearings</td>
<td></td>
</tr>
<tr>
<td>D6.1. Sea bed surveys</td>
<td>T2.4. Pitch system</td>
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</tr>
<tr>
<td>D6.2. Rotor auxiliary systems</td>
<td>T2.5. Spinner</td>
<td></td>
</tr>
<tr>
<td>D6.3. Met station sensors</td>
<td>T2.6. Rotor auxiliary systems</td>
<td></td>
</tr>
<tr>
<td>D6.4. Met station auxiliary systems</td>
<td>T2.7. Fabricated steel components</td>
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<td>D6.5. Met station structure</td>
<td>T3. Tower</td>
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<thead>
<tr>
<th>Installation &amp; Commissioning</th>
<th>Other Infrastructure and Logistics</th>
<th>Financing</th>
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<tr>
<td>I0. Installation &amp; Commissioning</td>
<td>O0. Maintenance ships, pontons, etc</td>
<td>F0. Financial costs during CAPEX</td>
</tr>
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<td>I1. Export cable-laying</td>
<td>O1. Remote monitoring</td>
<td></td>
</tr>
<tr>
<td>I1.1. Trenching vessel (dayrate)</td>
<td>O2. Facilities on land</td>
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<tr>
<td>I1.2. Export cable-laying vessel (dayrate)</td>
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<td></td>
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<tr>
<td>I2. Foundation Installation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>I3. Array cable-laying</td>
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<td></td>
</tr>
<tr>
<td>I4. Construction port</td>
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<td>I5. Offshore substation installation</td>
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<td></td>
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<tr>
<td>I6. Sea-based support (crew vessels, barges etc.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>I7. Turbine Installation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>I8. Commissioning</td>
<td></td>
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