LEVELISED COSTS OF ENERGY FOR OFFSHORE FLOATING WIND TURBINE CONCEPTS

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PREFACE

This thesis is carried out to conclude our Master of Science - Industrial Economics degree programme at the Department of Mathematical Sciences and Technology at the Norwegian University of Life Sciences. The thesis is interdisciplinary, and is predominantly based on knowledge and understanding gained through our time at the university. The involved work has been carried out through close cooperation between Catho Bjerkseter and Anders Ågotnes, and represents an extent of 60 credits, corresponding to 1 800 working hours.

The main purpose of the thesis is to evaluate and compare Life Cycle Costs and Levelised Costs of Energy for a series of fictitious wind farms consisting of wind turbines of different conceptual or realised designs, located far offshore. The background for the thesis is the development of two wind turbine substructure concepts, denominated *TLB B* and *TLB X3*, developed in close cooperation between the Norwegian University of Life Sciences and the Norwegian Institute of Energy Technology. The thesis illuminates important costs related to development, construction, operation and disengagement of commercial-scale offshore wind farms. Offshore wind energy is an exciting area of many unanswered problems, especially with regards to floating technologies, and this thesis is written with hopes of illuminating key aspects, and perhaps contribute to further industry development.

We gratefully acknowledge the support and assistance received from a number of individuals and companies. We would especially like to thank Marte Aaberg Midtsund and Carl Sixtensson (DNV Kema), Dieter Rabaut (DEME), Sigrid Ramuz Bomann-Larsen (Fearnley Offshore Supply), Eirik Byklum (Statoil), Kolbjørn Moldskred (Ulstein Design & Solutions), Steinar Ekrem (Viking SeaTech), Petter Heyerdahl (UMB), SWAY AS and Vryhof Anchors. A special gratitude goes to René van de Pieterman and his colleagues at the Energy Research Centre of the Netherlands, for letting us use their specialised Operation and Maintenance cost estimator software, and continued support in the process.

Our thesis advisors, Professor Tor Anders Nygaard and Ph.D. candidate Anders Myhr, deserve a special acknowledgment for their guidance and support through the thesis process.

Last, but not least, we wish to thank family and friends, in particular Hilde Raknes Hellberg and Marianne Foldøy Byberg, for their continued support throughout our time at the Norwegian University of Life Sciences.

Ås, May 15. 2013

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ABSTRACT

This master thesis is a part of the development of the floating TLB B and TLB X3 wind turbine concepts, developed by the Norwegian University of Life Sciences and the Norwegian Institute for Energy Technology. The thesis focuses on all costs occurring through different life cycle phases of a wind farm, from wind farm development, production, acquisition and installation of components, operation and maintenance of the wind farm, and finally wind farm disengagement and decommissioning. All costs are found within expected cost ranges. Total costs are discounted to values at equal points of time, and assigned to expected wind farm energy production, to find costs per produced unit of energy, so-called *Levelised costs of energy*. To evaluate the economic viability of the TLB concepts, the concepts are compared to floating and bottom-fixed concepts, presented in section 2.1. These concepts are chosen for comparisons due to their level of development, as all concepts are realised either through pilot projects or on a commercial scale. Additionally, these concepts are associated with relatively high levels of available and reliable data.

Total life cycle cost analyses are differentiated into five distinct phases:

1. Development and Consenting Costs: All costs associated with wind farm development, estimated based on generic sources. Comparable concepts are not assigned differentiated costs.
2. Production and Acquisition Costs: All costs associated with production and acquisition of key wind farm components, such as turbines, substructures, mooring systems and all electrical components. Cost estimations are based partly on generic sources, partly on industry sources and partly on assumptions relative to known reference values. Concepts are assigned differentiated values with respect to all cost categories except electrical components, and the main differences between concepts are illuminated in this phase.
3. Installation Costs: All costs associated with installation of wind turbines, mooring systems and electrical components. Cost estimations are based on generic sources and industry sources for bottom-fixed concepts, used as reference bases for floating concept assumptions and estimations due to lack of available data. Concepts are differentiated, but cost differences are not realised to the same extent as for production and acquisition costs. Installation processes are based on conventional installation methods.
4. Operation and Maintenance Costs: All costs associated with operating and maintaining wind farms. Costs are simulated using specialised software, and are only differentiated between floating and bottom-fixed concepts.
5. Decommissioning Costs: All costs associated with disengagement of the wind farms, through reverse installation operations and revenue from scrapping of components. Cost estimations are based on concept-specific installation costs and scrap potential.

Life cycle costs are discounted into levelised costs of energy, before sensitivities to changes in key cost drivers are presented.

Preliminary analyses indicate the TLB B concept to be the favourable floating solution, although concept energy costs are highly sensitive to water depths. The TLB B concept seems to be directly competitive to bottom-fixed monopile concepts.

CONTENTS

Figure 1: Hywind, the world's first megawatt scaled floating wind turbine (Refsdahl 2011)

1. INTRODUCTION

The main purpose of this section is to declare the goals of the thesis, as well as certain limitations and simplifications set. Additionally, background information relevant to harvesting of wind energy is presented.

1.1 Background

This section is intended as a superficial background introduction to offshore wind energy through history, present situation and potential, as well as an overview of energy costs and wind power technology.

1.1.1 Wind Power Introduction

The kinetic energy of the wind has been harvested by man for thousands of years, with sail-driven boats on the river Nile in Egypt as early as 5000 *B.C.* as one of the earliest known examples. By 200 *B.C.*, wind energy was used to pump water and grind grain in China and the Middle East, hence the commonly used denomination *wind mills*. By the 11th century these technologies spread to Europe, where they particularly established a foothold in the lowlands of the Netherlands and Denmark. (U.S. Department of Energy 2013)

After improving wind mill design and technology over centuries, the first electricity producing wind turbine was developed by Scottish professor James Blythe in 1887, and by the next year, American inventor Charles Brush produced the first large-scale electricity producing wind turbine. The first megawatt-sized turbine was connected to a local, American grid in the early 1940s, and increasing oil prices and raised awareness of renewable energy benefits acted as a spur to further technology development. The world's first commercial scale wind farm, producing 600 *kW*, was opened in New Hampshire in 1980. (Norwegian University of Science and Technology 2013)

As of 2013, the world's largest operational wind is the Jiuquan Wind Power Base (Figure 2) in the Chinese Gansu province, with an installed capacity exceeding 5 *GW* and a proposed capacity of approximately 20 *GW* (Schneider & Smith 2011).

Figure 2: Scenery illustration from Jiuquan Wind Power Base (Schneider & Smith 2011)

By 2012, wind energy production accounted for approximately 500 *TWh* of annual electricity production worldwide, equalling almost 3 % of the global electricity consumption (World Wind Energy Association 2012a). Today, global wind power capacity exceeds 250 *GW*, with

China, USA, Spain and Germany as the predominating countries (World Wind Energy Association 2012b). However, a certain stagnation in land-based wind farm development in the bigger markets has been observed, with offshore wind power production developing at a much higher rate (World Wind Energy Association 2012b). The distribution of global installed capacity of wind power is presented in Figure 3.

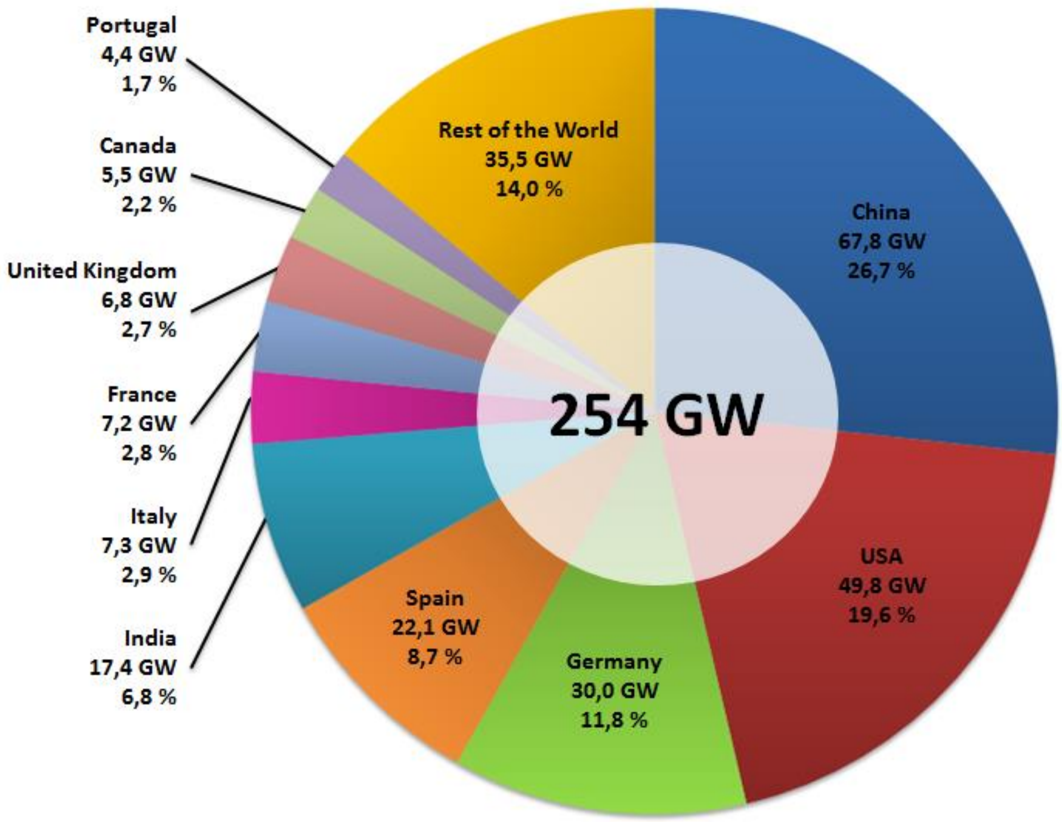


Figure 3: Global installed wind power capacity, derived from (World Wind Energy Association 2012b)

Denmark has been a pioneer country in developing offshore wind energy production. The world's first offshore wind farm, Vindeby, was opened off the Danish coast in 1991, and the Danish coasts are home to the world's top two energy producing offshore wind farms, Horns Rev 2 and Rødsand 2 (Lindø Offshore Renewables Center 2011).

By end of 2011, the total offshore wind power capacity exceeded 3.5 *GW*, accounting for approximately 1.5 % of the global wind power capacity, with only two out of thirteen countries with operational offshore wind farms situated outside of Europe. Close to all of the offshore capacity as of 2013 comes from bottom-fixed wind turbines, only a minuscule fraction of the capacity represents floating pilot wind turbines. (World Wind Energy Association 2012a)

Shores of Northern European countries account for majorities of the world's largest offshore wind farms, with 22 of the largest 25 operational farms, ranging from approximately 60 to 500 *MW*, and majorities of farms under construction, ranging from 100 to over 600 *MW*. As Figure 4 suggests, the UK, Denmark and Germany account for a large number of the world's largest operational and under-construction wind farms, as well as a large number of proposed wind farms with sizes ranging from approximately 1 to 2.5 *GW*. (Wikipedia 2013)

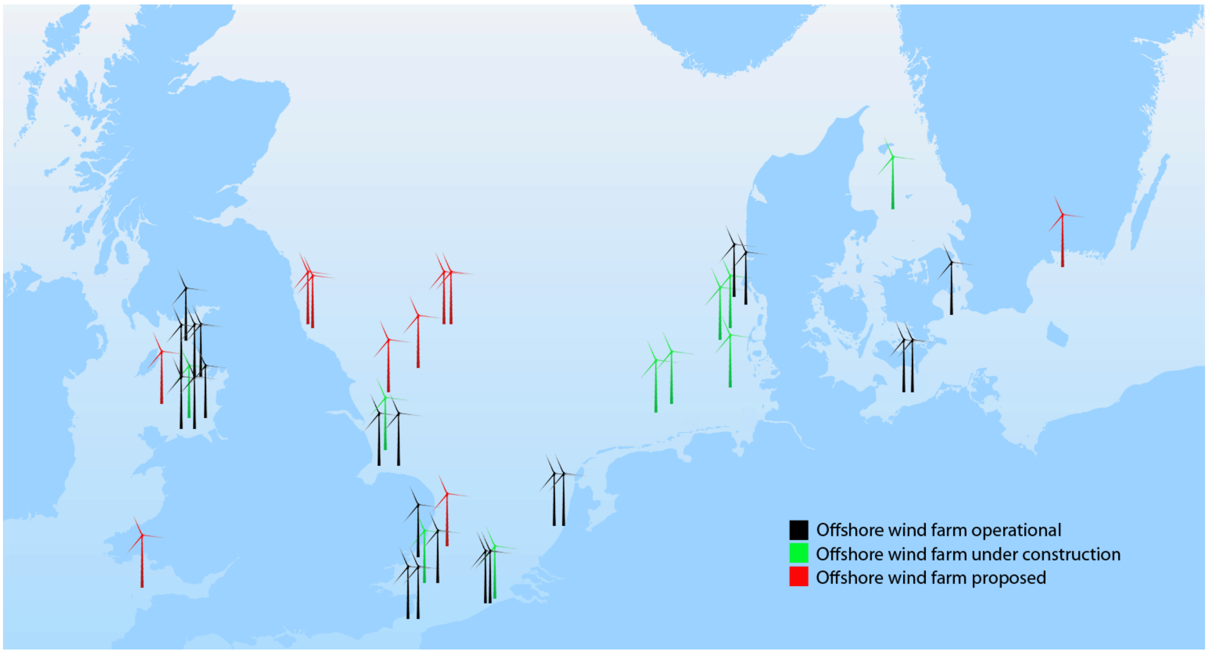


Figure 4: Map of the largest offshore wind farms of Northern Europe, derived from (Wikipedia 2013)

Due to both visual and acoustic pollution and dependency of large land areas, expansion of land-based wind energy production has been a root of conflict between society and developers. As a result of this, an increased focus on building wind farms offshore has emerged over the last decades. Offshore wind energy production provides numerous advantages over land-based activity:

- Greater applicable areas and less controversial area usage, allowing for higher numbers of turbines, excluding potentially expensive land rent and minimising the grid complexity
- Turbines can be larger since transportation by sea is less restricted by turbine size
- Higher wind speeds and less wind turbulence due to less surface roughness makes offshore wind more suitable for energy production (European Wind Energy Association 2009b). Higher average wind speeds create the opportunity for offshore wind turbines to generate a higher percentage of the maximum output compared to onshore wind turbines (higher capacity factor)
- Lenient restrictions against audible pollution and visual impact allow larger turbine blades rotating at higher speeds, which in turn lead to an increase in possible energy production

At the same time, offshore wind energy production also provides numerous disadvantages over land-based activity:

- Turbines need to operate in a more challenging marine environment, which among other factors is expected to increase turbine costs
- Less availability due to distance and weather conditions, increasing difficulties for installation, maintenance and repair of wind turbines and power cables
- Installation of offshore wind turbines is more complex than installation of onshore equivalents, and requires specialised vessels which are both scarce and expensive

1.1.2 European Plan on Climate Change and Offshore Wind Potential

In March 2007 members of the European Union proposed the *European plan on climate change*, the so-called 20-20-20 plan, which was adopted by the European Parliament by December 2008, in order to play a key role in negotiations for extending the Kyoto Protocol. The plan’s nickname comes from three of its main targets (European Commission 2012a):

1. Decrease total energy consumption by 20 % by increasing energy efficiency
2. Reach 20 % of total energy consumption from renewable sources of energy
3. Cut emissions of greenhouse gases to 20 % below the 1990 levels by year 2020
   Propositions to increase this target to 30 % have been raised

In order to reach these targets, one will have to focus on utilising the vast resources provided by nature. A 2007 study conducted on behalf of Enova SF, suggests that the theoretic, annual potential for offshore wind power along the Norwegian coast exceeds 14 000 *TWh*, of which almost 95 % are at depths inaccessible for bottom-fixed technologies (Sweco Grøner 2007). A study conducted by Greenpeace indicates a conservative annual electricity production of nearly 250 *TWh* by North Sea offshore wind projects due to be developed between 2020 and 2030 (De Decker et al. 2008).

Offshore wind power has a tremendous potential globally as well as in the North Sea. Studies have shown that waters off the Californian coast in close proximity to densely populated areas with spare capacity in existing power grids, provide an annual viable offshore wind potential of more than 660 *TWh*, with approximately 90 % of the potential situated in deep waters (Dvorak et al. 2009). After the 2011 nuclear disaster at the Fukushima nuclear power plant, an increased focus on clean energy has emerged in Japan, with offshore wind power as a strong candidate. The Japanese coast provides large potential for offshore wind power, but only a small percentage of this potential is exploitable using bottom-fixed concepts, so developing feasible floating concepts will be key in developing Japanese offshore wind industry (Arakawa 2012). Figure 5 shows that both the North Atlantic and the North Pacific Ocean have tremendous wind energy potential available near populated areas, developed in 1985 by the U.S Department of Energy based on 1980 wind data.

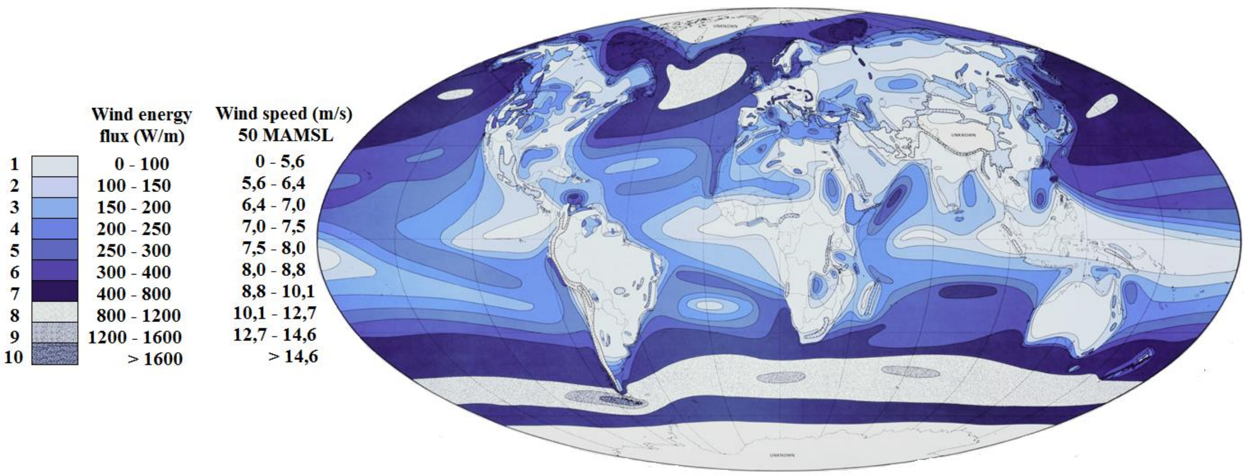


Figure 5: Global wind energy potential (U.S. Department of Energy 1985)

European Supergrid

Traditionally, power plants, with exceptions of hydro and nuclear power plants, have been positioned in the near vicinity of load centres, where majorities of the energy are consumed. Seeing as renewable energy sources, especially offshore sources, in many cases are more abundant far from load centres, viable exploitation of renewable sources requires a solution able to transfer power from production site to where the power is likely to be employed. The European Union has proposed a so-called *Supergrid*, a network of cables capable of transferring high voltage power between designated load centre locations on the European continent, both large populations and to aid in electrifying oil and gas installations in Northern European waters. As of 2013, a number of large-distance high voltage links transferring large amounts of power over sea exist, predominantly in Northern Europe, e.g. connections between Scandinavian countries and the European mainland and connections between the Great Britain and the European Mainland. A proposed expansion of this grid could aid in lowering electricity costs in participating countries and better cope with variations in renewable energy source availability. Connecting multiple offshore wind farms to a nearby, passing continental link of high capacity could aid in reducing energy costs by reducing necessities to directly connect wind farms to national, onshore grids. (Edwards 2011)

Figure 6 shows an example on how the currently operating international Northern European power cables are proposed to be further developed into a Northern European Supergrid. The Supergrid layout includes terminals and nodes both near population centres and near major, offshore installations.

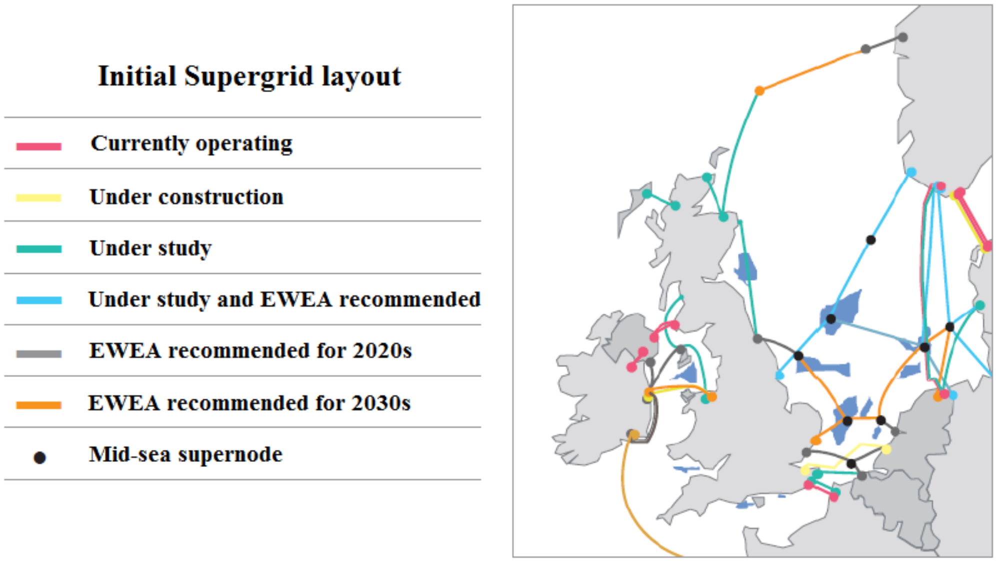


Figure 6: Example of a Proposed European Super Grid (Edwards 2011)

Norwegian offshore oil and gas installations contribute to approximately one quarter of the country's CO_2-emissions through gas turbines employed to produce utilised electricity. Connecting a proposed super grid to offshore oil and gas installations could reduce greenhouse gas emissions coming from offshore gas turbines, but guaranteeing electricity to come from renewable sources would prove to be difficult, given how European electricity often is produced from non-renewable sources. (Høgskolen i Østfold 2012)

1.1.3 Energy Costs and Support Mechanisms for Renewable Energy

Although being a controversial theory, a supported public opinion is that mankind's increasing use of energy since the start of the industrial revolution has had severe negative impacts on environmental conditions on a global basis, embodied through temperature changes portrayed in Figure 7. This has lead to increased efforts on reducing consumption of energy from non-renewable sources.

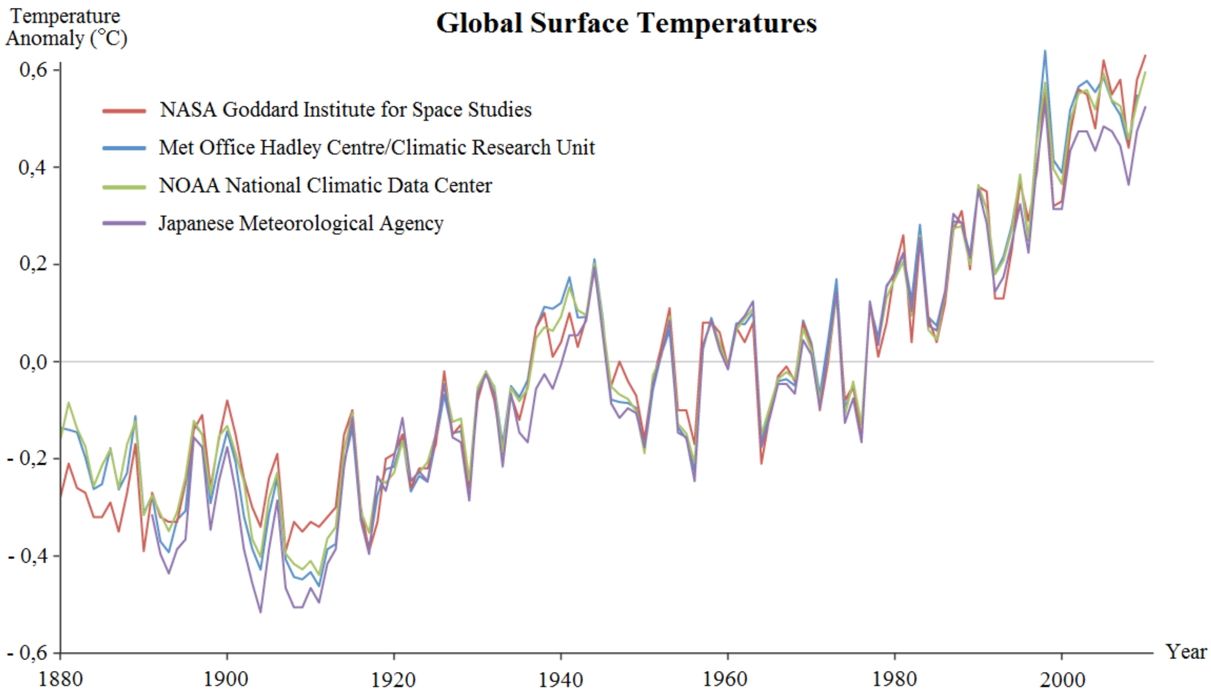


Figure 7: Global surface temperature change over time (NASA/Simmon 2011)

Corresponding with the European plan on climate change (European Commission 2012a), one possibility for reducing negative impacts from energy use seems to be to increase the use of energy generated by renewable sources instead of using energy from non-renewable sources.

As Figure 8 suggests, renewable energy is generally more expensive than traditional, fossil fuels, especially through capital costs. This is mainly due to the fact that renewable technologies have not had the same time to mature to allow costs to fall, thus making investment in and use of renewable energy sources less favourable than non-renewable sources from a strictly economical point of view. In addition to this, renewable energy projects are often deemed riskier due to uncertainties regarding technology and resource reliability and availability. (Hogg & O'Regan 2010)

Independent sources indicate the current costs per *MWh* of European offshore wind energy to be in the approximate region of €^{2013} 135 - 175 (Douglas Westwood 2010; Scottish Enterprise 2011; The Crown Estate 2012), of which approximately 80 % come from capital costs associated with construction and installation of the farm, while the remaining value comes from costs related to operation and maintenance of offshore wind energy plants (Interational Renewable Energy Agency 2012). By comparison, European onshore wind energy is expected to have costs of roughly two thirds of its offshore equivalent, with lower values expected for Northern America and Asia (Interational Renewable Energy Agency 2012).

However, severe potential reductions in offshore wind energy costs are suggested through a variety of cost reduction potentials, e.g. standardisation, optimisation and specialisation of components in a maturing industry, technological developments, making supply chains more efficient, taking advantage of expertise within the existing oil and gas industry etc. Costs of European offshore wind energy based on bottom-fixed plants are indicated at 20 % - 30 % lower than current costs (Scottish Enterprise 2011; The Crown Estate 2011).

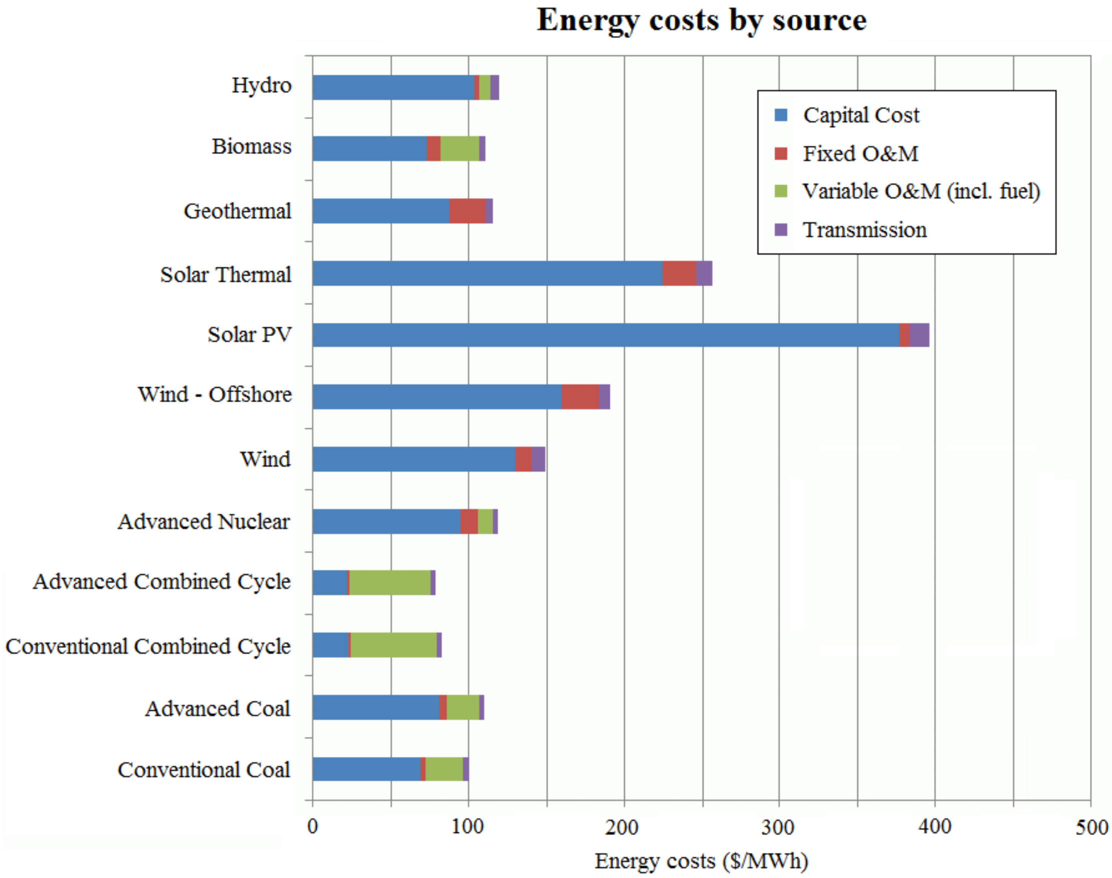


Figure 8: Energy costs by source (U.S. Energy Information Administration 2010)

Consideration to climate, environment and public health is not the only reason to encourage development of renewable energy industries. Investing in new technologies may help increase national and in particular local employment near renewable energy plants. Additionally, technology development may act as a foundation for export of goods and services, especially through expertise through so-called “first mover advantages”.

The Arab Oil Embargo of 1973 demonstrated the Western World’s dependency on imported oil, and to be as self-supported as possible with inexpensive energy, and thus reduce dependency on imported energy, is still an important subject for most countries. Development of technologies capable of exploiting a country’s energy resources is an important step in reducing energy import dependencies, which is high in many European countries, as presented in Figure 9. Reducing dependency on non-renewable sources may also act to insulate national economies from volatilities in fossil fuel prices. (Authen 2013)

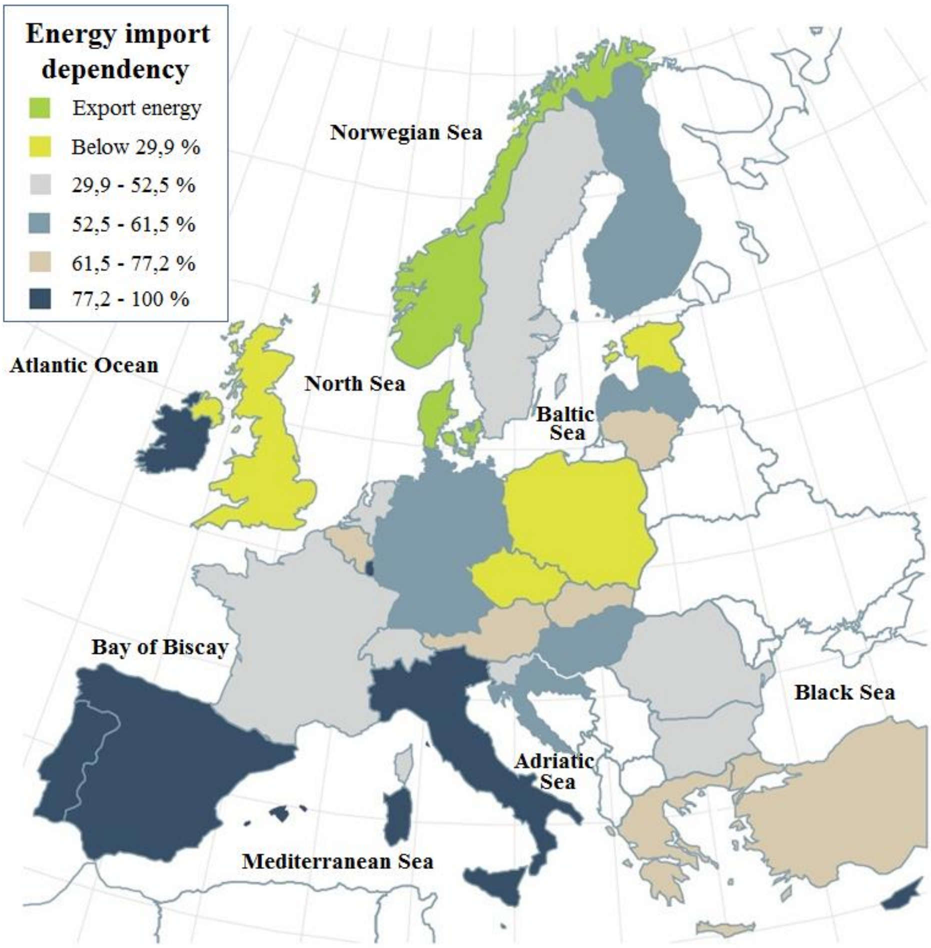


Figure 9: European energy import dependency as of 2008 (Barstad 2007)

In order to increase renewable energy use and urge a development of renewable energy technologies, authorities worldwide encourage renewable energy investments and renewable energy use through various support mechanisms. Here we aim to discuss some of the more common mechanisms for increasing renewable energy production or energy efficiency. Note that a combination of mechanisms is commonly used to support renewable energy investments and production (Econ Pöyry 2008).

Support Mechanisms

Three main categories of support mechanisms will be presented. These are feed-in tariffs and feed-in premiums, quota systems and fiscal strategies.

Feed-in Tariffs and Feed-in Premiums

Feed-in tariffs and premiums describe a support mechanism where authorities grant producers of renewable energy either a given premium per energy unit on current energy prices, or guaranteed a minimum unit price. The amount of compensation varies between energy sources. Feed-in tariffs and premiums can be described as so-called *compensation regulation*, where the authorities set the level of compensation, and the market regulates the amount of compensation realised (Econ Pöyry 2008). For electricity producers, feed-in tariffs are more predictable than feed-in premiums, as the level of received compensation under feed-in tariff schemes solely depends on energy production, and not additionally on energy prices realised in the market.

Quotas

Quotas describe a support mechanism where authorities award quotas to producers of renewable energy, and impose a mandatory purchase of certain amounts of these quotas onto energy consumers (i.e. power companies responsible for distribution of energy to industry and private use). This generates a market for both energy and quotas, and ensures lower prices from renewable energy producers, more production of renewable energy and potentially less production of traditional energy. Quotas can be described as so-called *amount regulation*, as the authorities decide the amount of support realised (i.e. the number of quotas imposed) and the market regulates the level of compensation (i.e. the quota price) (Bye & Hoel 2009).

Fiscal Strategies

Fiscal strategies comprise a number of financial incentives for increasing renewable energy production awarded, and some examples are subsidies of production facilities or investments, subsidies set to increase focus on technological development through R&D, and tax deduction for renewable energy producers. Some countries deploy so-called tendering strategies, where regulators decide a set volume of renewable energy desired produces, and set a support regime for this very volume over a set period. Another fiscal strategy to strengthen the position of renewable energy is imposing increased taxes and fees on use of conventional, non-renewable energy. However, the latter strategy cannot directly be identified as a support mechanism, rather as an indirect strategy to increase renewable energy use. (Authen 2013; Navigant Consulting Inc 2013)

Effects of Different Support Mechanisms

Comparisons of wind power capacity and wind power growth in different European countries indicate that both capacity and growth tend to be higher in countries where feed-in tariffs or feed-in premiums are used than countries based on quota systems, where no significant penetration of wind energy is experienced. Consumer prices for energy also tend to be lower in countries where feed-in strategies are dominant. (Baumgaertner 2013; European Wind Energy Association 2009a)

Tax deduction, either through deduction on taxes paid on revenues or through investment incentives are usually only beneficial to larger, profitable companies, and tend not to significantly reduce capital expenditures. In order to make increased taxation on non-renewable energy beneficial to renewable energy producers, these increased taxes somehow need to be channelled into renewable energy projects. If such distribution of increased taxes is not realised, renewable energy producers are likely to see few effects on their economics. (Baumgaertner 2013)

In order to have a flourishing renewable energy industry leading to profitable, mature industries, governments have to provide support mechanisms balanced enough to attract new entrants, but at the same time firm enough in order not to attract an unfortunate rush of stakeholders, so-called *windfall effects*. A suitable legal framework has to exist, in order to clarify obligations and duties for various stakeholders in a growing, renewable energy industry. Support mechanisms should be sustained over periods long enough to ensure capital costs allocated over adequately big production volumes. The German feed-in tariff system is by many regarded as the world's most promising for stimulation of further wind energy growth, although generous feed-in tariffs may encourage over-investments. For energy producers, incentives through quota systems tend to be unpredictable due to the fact that the market itself is responsible for determining the level of support. Tax deductions and investment support mechanisms also tend to be unpredictable by not accurately clarifying the expected level of support. (Baumgaertner 2013; Navigant Consulting Inc 2013)

Figure 10 shows the main support mechanisms for renewable energy in Europe. The figure shows that mechanisms involving feed-in strategies are prevailing for the Northern European countries with the most dominant wind energy industry. Additionally, the figure shows some countries utilise a strategy comprising of a combination of the mentioned categories. One example is Belgium, where *Green certificates* are employed. These may be viewed as quota obligations. However, the price of these certificates are set by the authorities, leading to a support mechanism which may be viewed as a combination of feed-in premiums and quota obligation support mechanisms (European Wind Energy Association 2009a).

Advantages and disadvantages related to different support mechanisms, as well as strategies and compensation employed in European countries with an existing or potential focus on offshore wind energy, is presented in Appendix 3.

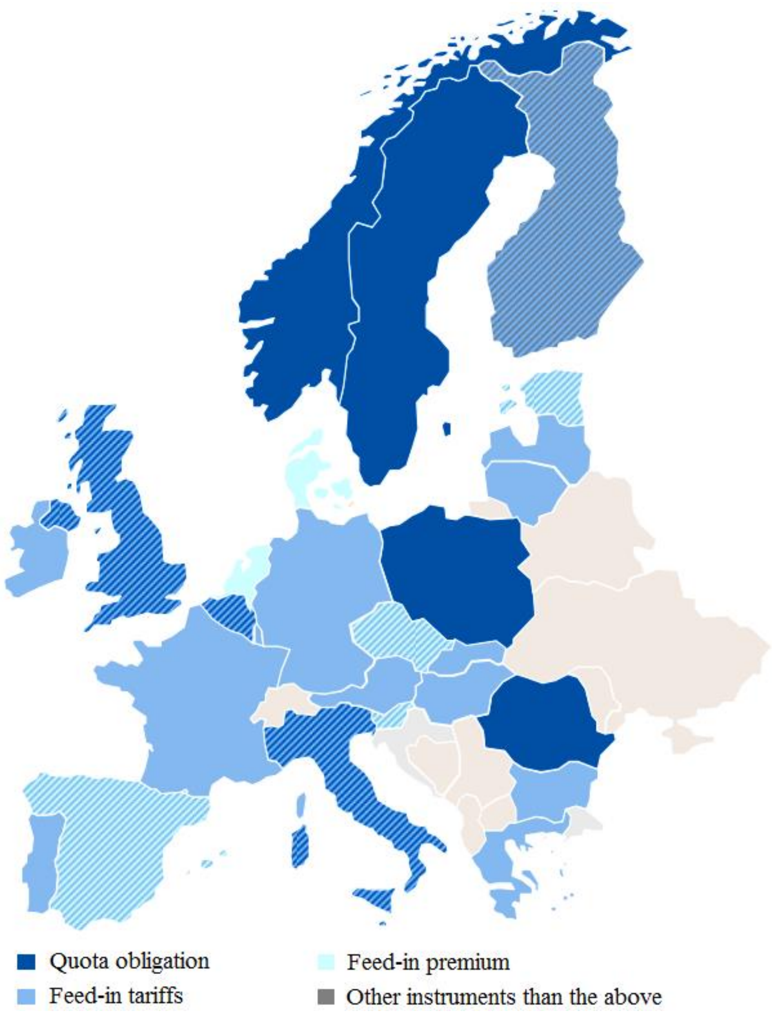


Figure 10: Main support mechanisms across Europe (Renewable Energy 2012)

1.1.4 Wind Turbine Description

A conventional offshore turbine, as defined in this thesis, consists of a tower, a rotor and a nacelle, all together comprised of as much as 8 000 different components (European Wind Energy Association 2009a). However, an industry focus is to simplify turbine designs and reduce the total number of components in order to reduce required maintenance efforts and improve stability.

For conventional turbines, the rotor is connected to a shaft which drives a generator through a gearbox, all components housed within a machine housing called the nacelle, as described in Figure 11. The most common design is a horizontal design, with the rotor rotating about a horizontal shaft. The combination of the rotor and the nacelle is sometimes described as the *Rotor Nacelle Assembly* (*RNA*), and is connected to the tower of the turbine.

If a substructure (fixed foundation or floater attached to the tower) is added to the turbine, we get what for this thesis is defined as a *wind turbine*.

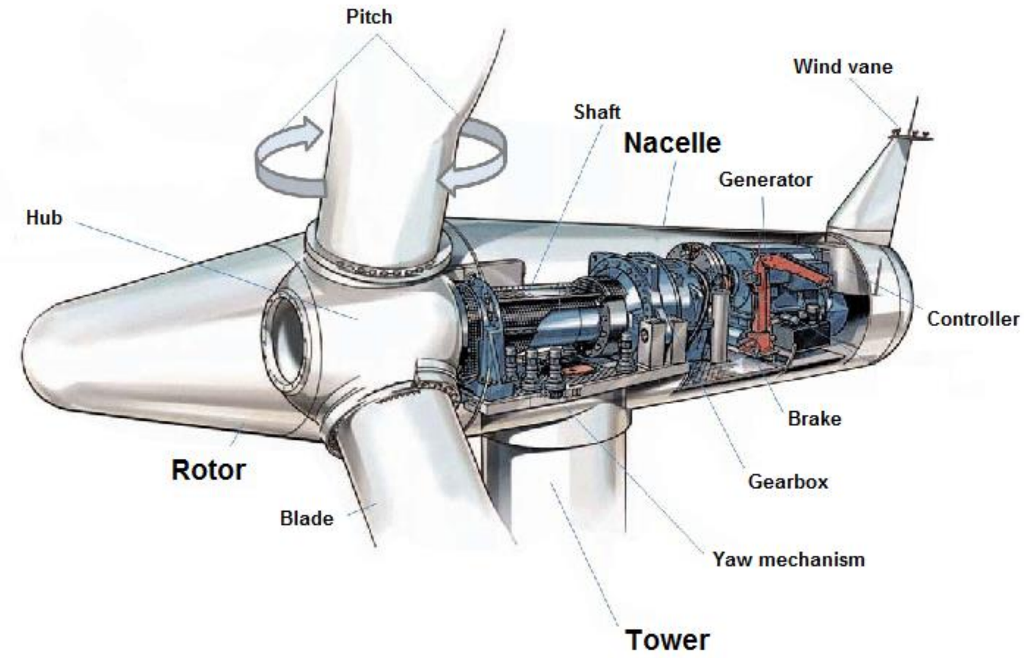


Figure 11: Turbine anatomy illustration, based on a Siemens 2.3 MW turbine (Siemens 2013)

Rotor

The rotor of a turbine consists of rotor blades connected to a rotor hub, which are rotated by the kinetic energy of the wind, in turn rotating the nacelle drive shaft. The rotor blades are commonly made of composite materials such as glass-reinforced plastic, and may these days exceed lengths of 60 *m*, illustrated in Figure 12. The rotor hub is generally made of cast steel, and includes possibilities to adjust the rotor blade angle through pitch control to ensure optimal wind utilisation (European Wind Energy Association 2009a). The rotor may be placed both upwind (on the windward side) and downwind (on the leeward side) of the turbine. An upwind placement of the rotor reduces problems with *wind shade* from the tower and nacelle, but requires stiffer and thus more expensive rotor blades in order to minimise the risk of the blades interfering with the tower due to being bent by strong wind loads (Danish Wind Industry Association 2011b).

Over time, an increase in rotor diameters for commercially available turbines has emerged. Increased rotor size is equivalent to larger areas from which wind energy can be extracted, leading to increased capacity of wind turbines. Trends in increase of rotor diameters and corresponding turbine capacity from 2002 to 2013, with rotor diameters marked with dark blue dots and rated capacities marked with lighter blue triangles, are illustrated in Figure 12 (European Wind Energy Association 2011).

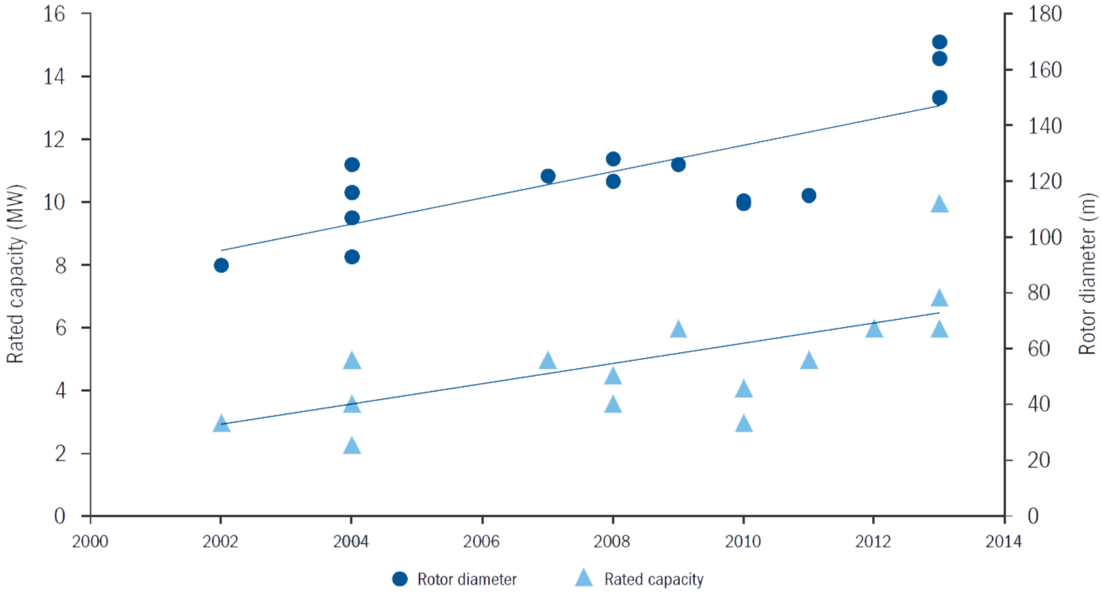


Figure 12: Rated capacity and rotor diameter for offshore wind turbines (European Wind Energy Association 2011)

Nacelle

The nacelle is usually made of fibreglass, and contains key electricity generation components such as drive shaft, brake system, gearbox, generator, power converter and transformer, although some components may be incorporated in turbine towers. The shaft is rotated at low frequencies, which are amplified in the gearbox to better suit the electricity generator. Direct current from the generator is converted to alternating current in a power converter, and transformed to higher voltages to satisfy grid requirements (European Wind Energy Association 2009a). If the wind turbines are placed far away from consumption centres, power may be converted and transformed to even higher voltages to minimise ohmic losses in export cables.

In addition to electricity generation components, the nacelle often contains a control unit to ensure optimal regulation of components with changing external conditions such as wind speed and direction. An active yaw system ensures the rotor is normal to the wind through rotating the RNA about the tower top for upwind systems, while a pitch system ensures optimal blade angles (American Wind Energy Association 2013).

Tower

Large wind turbine towers are usually constructed from tubular sections of rolled steel, commonly bolted together. Increasing rotor sizes enhance the possible energy which can be harvested from the wind, leading towers to often range 80 - 100 *m* tall. For offshore constructions, large vertical distance between mean sea water line and rotor blades is desirable to diminish the risk of the rotor to be destroyed by waves caused by extreme weather conditions. Also, higher towers make more preferable wind conditions at higher altitudes exploitable.

Substructures

Common foundations for land-based wind turbines include soil-buried concrete foundations, popular on the European continent, and anchoring struts driven and casted into the bedrock, commonly used in countries of challenging soil conditions, e.g. Norway. Offshore wind turbines are placed several kilometres off the shore, and may either be bottom-fixed, with foundations resting on or in the seabed, or floating structures, with towers attached to floaters on the water surface. The most common offshore substructure types are discussed here.

Offshore substructures

The most common bottom-fixed substructure is the *monopile*, consisting of a long steel pipe which could be regarded as an extension of the tower down into the seabed. This is a fairly simple foundation technique, but is poorly suited for depths exceeding 30 *m*, and raises environmental concerns in the assembly phase due to sound pollution from driving the foundation into the seabed. Ranging second in world-wide commercial use is the *gravity-based substructure* (*GBS*), where the tower is connected to a heavy structure resting on the seabed. The structure is partly constructed on land, and then transported to site where the weight is increased by adding concrete, sand, rock etc. GBSs are used at depths up to approximately 30 *m*, where environmental load impacts are modest. In deeper waters, so-called *Space frame substructures*, structures constructed from several piles, are preferable to monopiles or GBSs. Space frame structures are often divided into *tripods* and *jacket structures*. Tripod structures are constructed from steel pipes, and consist of a central shaft with three legs that are driven into the seabed, as is the case with monopile structures. Jacket structures consist of significantly less steel than tripods because of steel positioning further away from the substructure central axis, making it a highly transparent structure. As for tripods, jacket structures include piles that are driven into the seabed. The substructure concepts are illustrated in Figure 13. (European Wind Energy Association 2011)

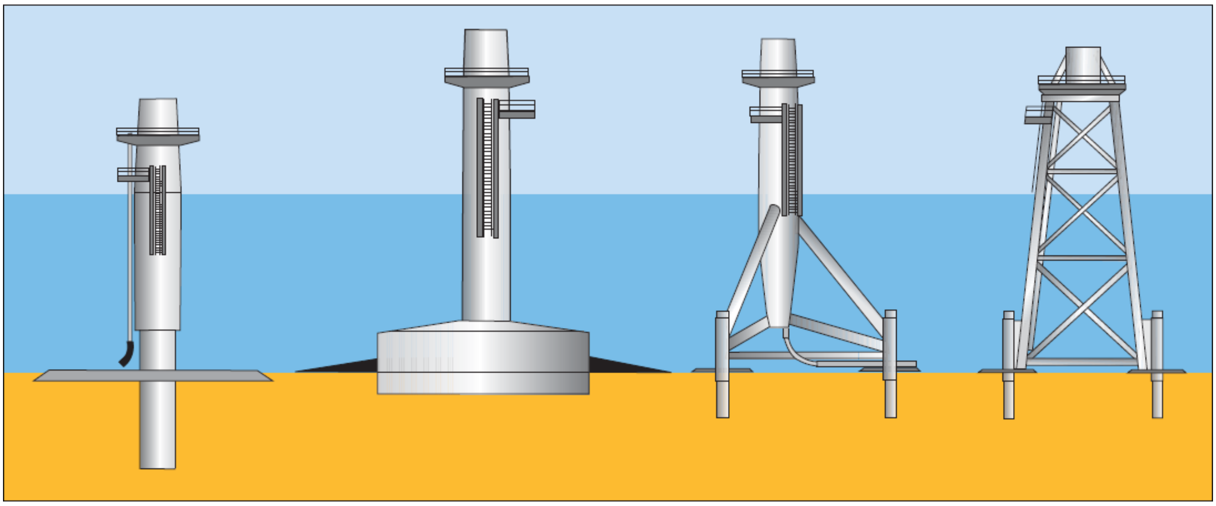


Figure 13: Bottom-fixed substructures. From left: Monopile, Gravity-based Substructure, Space Frame (Tripod) and Space Frame (Jacket) (European Wind Energy Association 2011)

For floating substructures, three main concepts have emerged: *ballast stabilised concepts*, *mooring line stabilised concepts* and *buoyancy stabilised structures*. Ballast-stabilised concepts are stabilised through righting moments caused by ballast positioned below a buoyancy centre, counteracting pitch and roll rotations and heave motions. One example of a ballast-stabilised substructure concept is the *spar buoy* shown in Figure 14. Mooring line stabilised concepts depend on excess buoyancy to provide tension in the mooring lines, which makes the structure float deeper than what would have been the case without the mooring lines. One example of a mooring line stabilised concept is the so-called *tension-leg platform* (*TLP*) shown in Figure 14, which has seen use in the oil and gas industry. The focus on increasing buoyancy may lead to reduced material costs, but subsequently the tension in the mooring lines may require improved anchoring technologies. Buoyancy stabilised structures achieve stability by optimal positioning of buoyancy elements on the substructure. Variations in external loads and impacts may be counteracted through varying these buoyancy elements, e.g. by controlling the level of ballast water within certain sections of the substructure. One example of a buoyancy stabilised concept is the semi-submersible platform in Figure 14. Note that a floater concept may be regarded as a combination of two or more of the mentioned main concepts. This is discussed in section 2.1. (Butterfield et al. 2005).

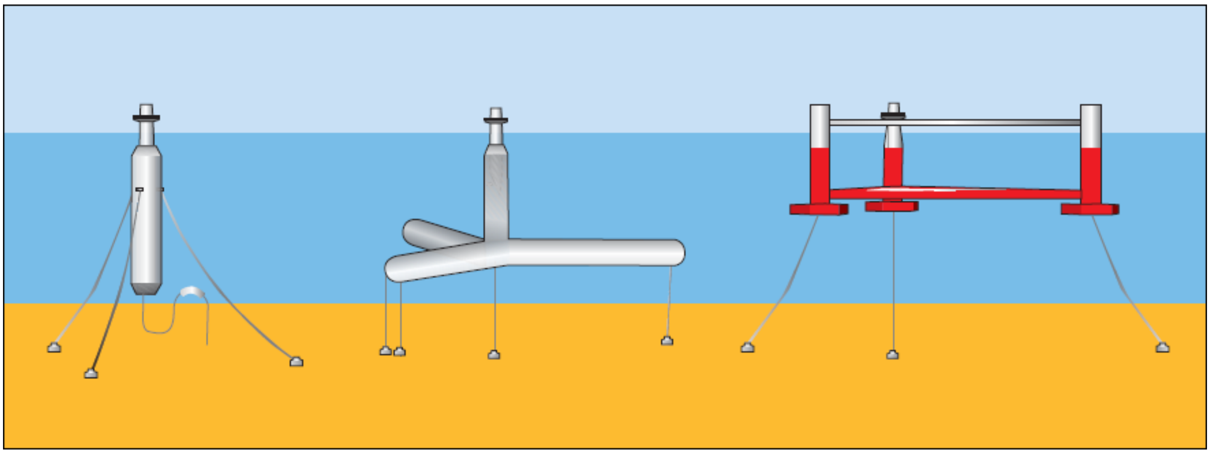


Figure 14: Spar, TLP and semi-submersible platform (European Wind Energy Association 2011)

Table 1 shows key qualities for different offshore substructures, with main focus on dominant bottom-fixed substructure types. In the table, floating platforms are not further differentiated, leading to generic results whose validity further rely on employed substructure concept.

Table 1: Comparison of different substructure systems, derived from (Mistri et al. 2010)

Comparison points	**Gravity-based Substructure**	**Monopile**	**Space Frame (Tripod)**	**Space Frame (Jacket)**	**Floating platform**
Preferred depth application	5 - 30 *m*	5 - 30 *m*	25 - 30 *m*	30 - 50 *m*	More than 50 *m*
Dependency of subsoil condition	Moderate	High	High	High	Low
Installation	Difficult	Moderate	Moderate	Moderate	Easy/Moderate
Manufacturing	Difficult	Easy	Moderate	Moderate	Easy/Moderate
Transportability	Difficult	Easy	Moderate	Moderate	Easy
Removal after design life	Difficult	Moderate	Easy	Easy	Easy

1.2 Problem Definition

This is a thesis intended to act as an overview of costs related to offshore wind energy based on floating or bottom-fixed concepts deployed at far offshore sites in a commercial scale.

The main purpose of the thesis is to compare levelised costs of energy for different floating wind turbine concepts.

1.3 Goals and Limitations

This section illuminates both goals intended to be answered during the thesis, and general limitation, simplifications and assumptions set.

1.3.1 Main Goals

We aim to perform an analysis where we investigate levelised costs of generated energy from different floating offshore wind turbine concepts with regards to total life cycle costs for the concepts, and compare with reference wind turbine concepts, both on- and offshore. This analysis is expected to be realised through several partial goals.

1.3.2 Partial Goals

1. Evaluation of *Life Cycle Costs* for various floating and bottom-fixed wind turbine concepts through development, production, assembly, maintenance and de-commissioning costs for fictitious large-scale wind farms, as described in section 2.2.1
2. Evaluation of per energy unit costs for the different concepts through *Levelised Cost of Energy* methodology, further presented in section 1.5.2.
3. Explore how costs are affected by changes in both concept-sensitive parameters, e.g. steel price and water depth, and also generic input parameters such as offshore distance, farm size, life span, turbine costs etc., to evaluate how different concepts react to changes in key cost drivers

1.3.3 Assumptions, Limitations and Simplifications

This section defines certain assumptions, limitations and simplifications set in order to maintain the contents of this thesis within the thesis scope.

Assumptions

Certain assumptions have been set prior to solving this thesis, including:

1. All comparable concepts are compared at equal terms with regards to commodity costs, vessel costs, component costs, life spans and site qualities
2. RNA costs are assumed equal for all concepts
3. Mature industries allowing effective large-scale production is assumed
4. Components are assumed to be produced near port, leaving transport costs negligible
5. The thesis intends to evaluate costs related to deployment of wind farms at far offshore sites

Where reliable data are scarcely available, several assumptions have been set in order to be able to compute certain cost elements. Examples include operation time consumptions, manufacturing costs and cost changes due to changes in wind farm qualities. These assumptions are further presented when employed.

Limitations

By reasoning that this is a thesis intended to evaluate economical aspects of offshore wind farm construction and operation, publicly available sources and sources based on personal correspondence with industry companies are assumed to give accurate data with regards to technical feasibility. When source data are scarce or seems improbable, values are discussed with thesis advisors and adjusted accordingly, indicated by stating thesis advisors as sources. All values estimated and presented in this thesis are intended not to be either too conservative or too liberal.

It has been decided to delimitate the thesis towards conceptual and experimental wind turbine installation methods, by assumptions that introduction of conceptual methods will entail assumptions of great uncertainty. Accordingly, installation costs for floating concepts are estimated based on use of existing vessels and existing technology, and horizontal transport of turbines is not evaluated. For descriptions of certain conceptual installation strategies, (Moss & Myhr 2009) and (Sanden & Vold 2010) are suggested.

Simplifications

According to offshore renewable energy consortium *ORECCA project* (Offshore Renewable Energy Conversion platforms – Coordination Action), two main locations in Northern Europe stand out as preferable locations for floating wind turbine projects; the northern coast of Scotland and the western coast of Norway, due to high wind resources, waters deep enough to support floating concepts and proximity to ports, population, grid infrastructure and production incentives (Airdoldi et al. 2011). Due to water depth dependencies, it does not seem feasible to compare floating and bottom-fixed concepts given a fixed location, leading to decisions not to set an exact location, besides stating a general Northern European location for the wind farms discussed in the thesis, making the thesis as simplified and generalised as possible. More information on wind farm qualities is described in section 2.2.1.

If a commercial, large-scale wind park is to be built, adequate respect to existing offshore activities such as oil and gas operations, shipping and fishing activities has to be shown, with existing petroleum installations and main shipping lines shown in Figure 15 (Airdoldi et al. 2011). Because of the simplifications set for this thesis, we choose not to take interaction with fisheries, oil and gas and shipping into more consideration than pointing out that interaction with these activities is a key part in developing a commercial wind farm.

When planning life cycle phases for an offshore wind farm, it is important to take into consideration that the ports and vessels required for all operations have to meet each other's requirements regarding depth and draft, operating space etc. Infrastructure experts indicate that for ports to be suited for offshore wind operations, a water depth of 10 - 15 *m* is required, with suitable Northern European ports shown in Figure 15 (Airdoldi et al. 2011). For this thesis, we assume that the offshore farm distance set in section 2.2.1 is the distance from the wind farm to a suitable port connected to adequate road and aerial infrastructure, and with suitable grid infrastructure with available capacity immediately accessible, generically illustrated in Figure 16.

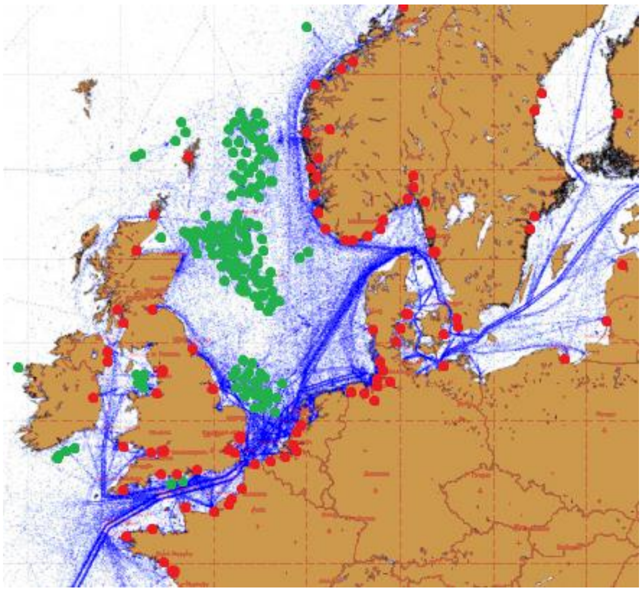


Figure 15: Shipping density (blue), Northern European oil and gas installations (green) and existing ports suitable to serve as bases for offshore energy installation and operation (red),derived from (Airdoldi et al. 2011)

To maintain a generic focus, we choose to disregard costs associated with seabed rent and fees coming from transmission of electricity, as these are cost categories expected to be severely dependant on location and country for an offshore wind farm project. Accordingly, any applicable support mechanisms are not quantified for this thesis. If an investment decision for a real-life wind farm were to be performed, adequate attention to such details should be paid, depending on project origin.

Figure 16: Envisioned port for offshore wind energy operations (Green Port Hull 2012)

1.4 Employed Terminology

The following gives a brief introduction to terminology used in the thesis, divided into general, economical and technical terminology. Note that a certain understanding of offshore wind energy production is required to fully utilise the information presented in the thesis. Additionally, knowledge of SI units and their derivatives, as well as common marine terminology, is expected.

General Terminology

Bulk	-	Untreated steel
Capacity factor	-	Ratio between annual actual energy production and nominal, theoretical production (provided full-capacity production at all times)
Comparable concepts	-	All concepts directly comparable with respect to substructure technology, i.e. floating or bottom-fixed concepts
Conservative	-	An estimate expected to be on the safe side of facts
Decommissioning	-	Disassembly, removal and recirculation of a wind turbine, last phase of the wind turbine’s life cycle
Deep water	-	Set to depths exceeding 50 *m* for this thesis
Generic sources	-	Sources stating generic information on wide areas within offshore wind energies. Often developed by independent consultants on behalf of government agencies. Examples include, but are not limited to, (BVG Associates 2012), (Douglas Westwood 2010), (Scottish Enterprise 2011) and (The Crown Estate 2010)
Liberal	-	Opposite of conservative
MSL and MAMSL	-	"Mean Sea Level" and "Metres Above Mean Sea Level"
NA	-	“Not Available” - The requested quality is not available
O&M	-	"Operation and Maintenance", activities associated with keeping a wind farm in adequate operational conditions
Offshore	-	At-sea activity
Onshore	-	Land-based activity
OW	-	"Operational window", the average percentage of time a certain operation is expected to be performed
Shallow water	-	Set to depths less than 50 *m* for this thesis
Thrust force	-	Horizontal force applied by wind on the turbine rotor
WoW	-	"Waiting on Weather", time spent waiting for weather conditions to improve enough to undertake certain operations

Economical Terminology

CAPEX	-	"Capital Expenditures", expenses or investments used to upgrade or obtain physical assets in order to create a future benefit
CAR	-	"Construction All Risks", insurance covering all types of construction risks and includes works brought on-site as part of a contract and temporary works constructed on-site
DECEX		"Decommissioning Expenditures", expenses associated with disengagement of the wind farm
EAR	-	"Erection All Risks", insurance covering plant and machinery construction risks
FID	-	"Final Investment Decision", refers to the time and action of deciding to make a capital investment in hope of gaining profits
Investment	-	A business expenditure performed in order to generate future monetary return
LCOE	-	"Levelised Cost of Energy", all discounted life cycle costs relative to discounted life time energy production, with all values evaluated at equal terms with respect to the time value of money
LCOE Analysis	-	"Levelised Cost of Energy Analysis", performing an economical analysis to calculate the levelised cost of energy of a product or project
Life time / Life cycle	-	The time spanning from the initial to the final phases of a product or project
LCC	-	"Life Cycle Cost", the total costs associated with a product or project over all life cycle phases over its entire life time
LCC Analysis	-	"Life Cycle Cost Analysis", performing an economical analysis to calculate the life cycle cost of a product or project
NPV	-	"Net Present Value", the present value of a future monetary amount or cash flow
OPEX	-	"Operating Expenses", expenses coming from performing normal business operations, in this thesis expenses coming from operating and maintaining a wind turbine or wind farm
WCD	-	"Works Completion Date" , refers to the point where 100 % of turbines are operational

Technical Terminology

AHTS	-	“Anchor Handling Tug and Supply”, multi-functional vessels designed for handling anchors, towing and operating as supply and assistance vessels
Mooring system	-	Complete system for mooring of a floating offshore structure, ranging from the attachment point on the floater to the seabed, including mooring lines, anchor and all transitional structures between the elements in question
Ballast	-	Heavy substance placed near keel of floating structure in order to improve stability by overcoming turning moments caused by forces due to wind and mass. Usually consists of either water or substances denser than water, such as sand, concrete or rocks
Bollard pull	-	Actual pull capacity of a vessel
Catenary mooring	-	Mooring system where substantial mooring line weights and lengths make mooring lines lie along the seabed, resulting in virtually one-dimensional anchor loads and dampening of construction motions
Crane barge	-	Vessel with an integrated crane able to perform heavy lifting operations in calm and protected waters
Crane vessel	-	Vessel with an integrated crane able to perform heavy lifting operations at sea
Creep	-	Elongation of fibre rope mooring lines from load strains and load variations
Day rate	-	Per day costs associated with rent of a certain vessel
EIA	-	"Environmental Impact Assessment", evaluation of environmental, social end economical impacts associated with a project
FEED	-	"Front-end engineering and design", transformation of conceptual designs into realisable solutions
Fibre rope	-	Ropes produced from synthetic fibres, commonly used as mooring lines
Floater	-	Main provider of buoyancy and substructure for floating offshore structures. Commonly described as ranging from 10 m above water line to the lowest point of the construction
Foundation	-	Substructure for land-based or bottom-fixed offshore wind turbines
Heave	-	Translation parallel to the Z axis, commonly understood as up-down motion normal to water level. See Figure 17
Hywind	-	Floating wind turbine concept developed by StatoilHydro, with a substructure consisting of a ballast-stabilised spar buoy with large draft

Jack-up vessel	-	Self-elevating crane vessel developed for installation of bottom-fixed wind turbines, specialised through having a number of legs used to hoist the vessel out of the water to protect against harsh seas
Jacket	-	Space-frame construction used as foundation for bottom-fixed wind turbines
Monopile	-	A steel pipe is driven into the seabed in order to act as foundation for bottom-fixed wind turbines
Nacelle	-	Housing for the wind turbine's gearbox, drive train, generator, brake etc.
Pitch	-	Rotation about the Y axis, see Figure 17
PSV	-	Platform Supply Vessel
Reliability	-	The probability that an item will perform its intended function for a specified interval of time under stated conditions
RNA	-	Rotor-Nacelle Assembly
Roll	-	Rotation about the X axis, see Figure 17
Rotor	-	Collective term for the assembly of rotor blades and rotor hub
Rotor blade	-	Rotating airfoil attached to rotor hub, which aids in transforming kinetic energy from the wind into electrical energy through driving a generator
Rotor hub	-	Transitional piece between rotor blades and the generator drive shaft
ROV	-	Remotely Operated Underwater Vehicle
Semi-submersible	-	Stable construction specially developed to cope with harsh weather conditions by being able to lower itself into the water
Significant wave height	-	The average wave height of the highest one-third of waves within a 20 minute period
Spar buoy	-	Large-draft floater concept where stability is achieved through ballast
Substructure	-	Bottom part of wind turbines, attached to tower. Either floater for floating concepts or foundation for bottom-fixed or land-based concepts
Surge	-	Translation parallel to the X axis, commonly understood as forwards-backwards motion parallel to water level. See Figure 17
Sway	-	Translation parallel to the Y axis, commonly understood as side-to-side motion parallel to water level. See Figure 17
SWAY	-	Wind turbine concept developed by SWAY AS. Stabilised through a combination of ballast, taut leg mooring and a tension rod system
Taut Leg Mooring	-	Mooring system where dampening occurs through tension and elasticity in the mooring lines, arriving the seabed at an angle
TLB	-	"Taut Leg Buoy" - floater design based on TLP technology, developed by the Norwegian Institute for Energy Technology (IFE) and the Norwegian

		University of Life Sciences (UMB). Subcategorised into TLB B and TLB X3
TLP	-	"Tension Leg Platform" - stabilisation technology for floating offshore installations for which excess buoyancy causes tension in anchoring cables
Tower	-	Elements of wind turbine located between nacelle and foundation/floater
Transition piece	-	Component used to attach the tower of a turbine onto a bottom-fixed substructure foundation
Turbine	-	For this thesis defined as tower, nacelle and rotor, but not foundation or floater
Vertical mooring	-	Mooring system based on vertical mooring lines and anchors capable of withstanding true vertical loads
Wind farm	-	A commercial assembly of wind turbines producing electricity
Wind Turbine	-	For this thesis defined as foundation/floater and turbine. Differs from *Turbine* through taking the foundation or floater into account
WindFloat	-	Wind turbine concept currently developed by Principle Power Inc. Floater consists of three-legged, semi-submersible platform, actively compensating for heave motions
Yaw	-	Rotation about the Z axis, see Figure 17

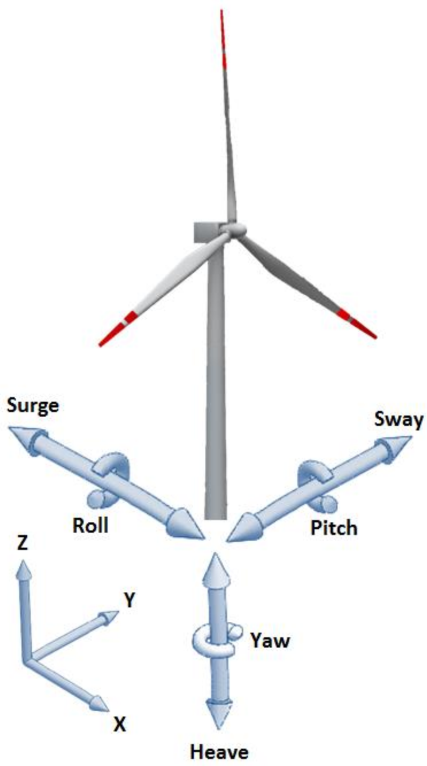


Figure 17: Axis system with corresponding translations and rotations

1.5 Methodology

The intention of this section is to present the methodology used in solving this thesis. Methodology includes evaluation of *Life Cycle Costs* expanded into a *Levelised Cost of Energy Analysis*. Presented are also economical evaluations and employed specialised software.

1.5.1 Life Cycle Cost Analysis

Life Cycle Cost Analyses are helpful when deciding between alternatives with different initial and operating costs, but satisfy the same requirements with regards to performance. In order to minimise the total life cycle cost, one should strive to minimise the total expenses relative to produced energy, and this can be achieved by weighing and comparing expenses in different phases during the project’s life cycle. (Shil & Parvez 2007)

Application and Background

In most cases, evaluation of investment expenses as the only criterion for investment decisions is a bad idea, as solutions involving smaller capital costs in the long run might be a more expensive alternative than solutions depending on larger capital costs due to high maintenance and operation costs. A common analogy used when describing Life Cycle Costs is the *Iceberg analogy*, as presented in Figure 18 (Shil & Parvez 2007). The figure highlights the dangers of only taking initial and visible costs into consideration when deciding between seemingly equivalent alternatives, as the majority of a project’s life cycle costs may seem invisible at first.

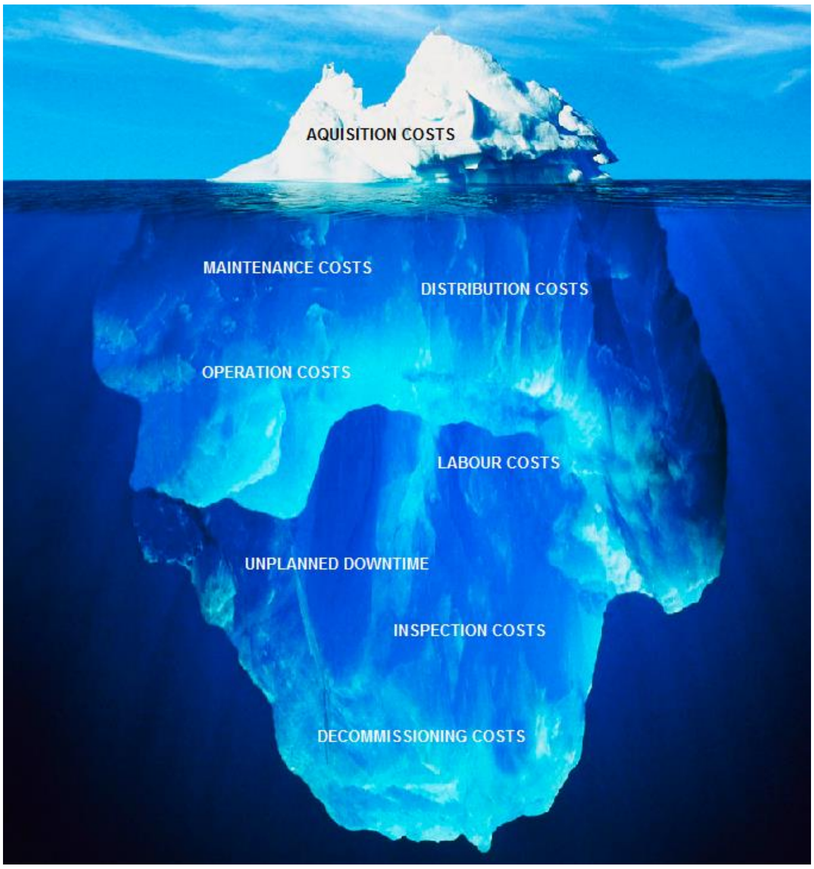


Figure 18: Iceberg of hidden costs, derived from (Clevenger 1996; Shil & Parvez 2007)

Common applications for LCC analyses include (Kawauchi & Rausand 1999):

- Comparison between alternative solutions and strategies in regards to concept, production, operation, maintenance etc.
- Assessment of a project's economic viability.
- Financial planning.

Life Cycle Phases and LCCA Cost Elements

In this thesis, a project's life cycle is defined to consist of the following five phases and corresponding cost elements (RTO/NATO 2007):

1. Development and consenting, where the project is defined, designed and developed.
2. Production and acquisition, where necessary components are either produced or acquired from external sources.
3. Installation, where all components are installed.
4. Operations and Maintenance, where necessary actions are taken to ensure the farm is producing electricity.
5. Decommissioning, where the farm is disengaged and refurbished.

Cost flows over the project's economic lifetime are evaluated at an early stage of the project, bearing the time value of money in mind.

1.5.2 Levelised Cost of Energy

In this thesis, the Life Cycle Cost Analysis is expanded into a Levelised Cost of Energy (LCOE) analysis, with use of Present Value methodology (section 1.5.3). The LCOE analysis evaluates results from the LCC analysis with regards to expected energy production, and gives the constant unit cost per energy unit of a series of cash flows adding up to the total life cycle cost of the energy generating facility, illustrated in Figure 19. The LCOE may be interpreted as the minimum unit price (discounted to present day prices) for which energy has to be sold in order to break even on the total investment (Black & Veatch 2010), and the formula for calculating the LCOE may be written as: (Interational Renewable Energy Agency 2012)

$$LCOE = \frac{\sum_{t=0}^{n} \frac{I_t + M_t}{(I+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(I+r)^t}} \qquad \textbf{\textit{(1)}}$$

Where:
LCOE denotes the average lifetime levelised cost of energy generation.
I_t *denotes investment expenses at time t.*
M_t *denotes operation and maintenance costs at time t.*
E_t *denotes energy generation at time t.*
r denotes the evaluation discount rate.
t denotes the time, ranging from zero to n.

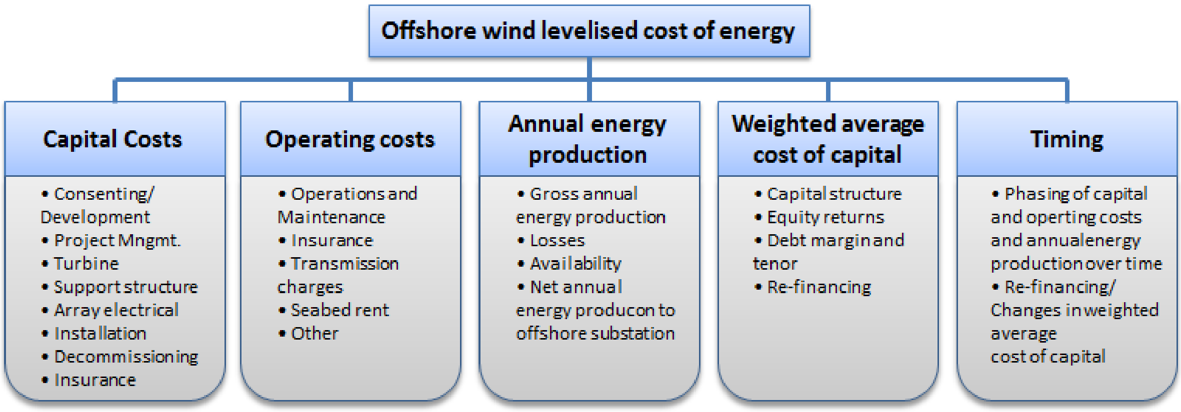


Figure 19: Levelised cost of energy model for a single site in a specific year, derived from (The Crown Estate 2012)

1.5.3 Economical Evaluations

This section will present the main economical methodology used to perform the analyses of this thesis, through conversion and valuation of monetary values and utilised discount rates.

Present Value Evaluation:

Different cash flows coming from expenses and revenues at different times have to be evaluated and compared at equal terms, as interest rates, possibilities for immediate use and uncertainties about the future makes a given amount of money at present time more valuable than the same amount of money in the future.

For this thesis, we will assess all life cycle costs at *Present values*, meaning all costs are evaluated at their reference time value. The present value of a series of costs and cash flows can be found using the following formula: (Jordan et al. 2008)

$$PV = \sum_{t=0}^{n} \frac{C_t}{(1+r)^t} \tag{2}$$

Where:
PV denotes the present day value of the future costs and cash flows.
C_t denotes a cost at time t.
r denotes the evaluation discount rate.
t denotes the time, ranging from zero to n.

Annuity Method:

The annuity method is used to determine the terminal capital consumptions of different expenses, and can accordingly be used to compare costs of investments in fixed assets to rate rents for the same assets. The annuities of an investment can be found using the following formula: (Jordan et al. 2008)

$$C = \frac{INV \cdot r}{1 - \frac{1}{(1+r)^t}} \tag{3}$$

Where:
C denotes the terminal cost.
INV denotes the present value investment cost
r denotes the evaluation discount rate.
t denotes the time frame.

Project Discount Rates

As discussed, costs will have different present values based on when they occur, and it is therefore important to evaluate future costs at an adequate time value. In doing so, we evaluate future costs and monetary values of a project using a specific discount rate depending on expected return from other, often less risky projects, the project risk and macro-economical qualities such as taxation and inflation.

The discount rate used in our project evaluations will be the *Weighted Average Cost of Capital* (WACC), and could be interpreted as what a company would have to pay to security holders for financing of projects and assets, or so to speak "the overall return the firm must earn on existing assets to maintain the value of the stock". The WACC is estimated by average cost of equity and average cost of debt, taking into consideration that some interest on debt in most cases are tax-deductible. The WACC can be found using the following formula: (Jordan et al. 2008)

$$WACC = \frac{E}{E+D} \cdot R_E + \frac{D}{E+D} \cdot R_D(1-T) \qquad \textbf{(4)}$$

Where:
E and D denote the market value of equity and debt, respectively.
R_E denotes the cost of equity, found from the CAPM model as a function of the risk-free rate, the expected return on the market portfolio and the specific asset's sensitivity to variations in the market portfolio.
R_D denotes the cost of debt found by adding a risk premium to the risk-free interest rate which could be achieved through low-risk value allocations.
T denotes the asset tax rate.

The preceding formula gives the nominal weighted average cost of capital, meaning that monetary inflation is not taken into account. In a 2007 paper conducted on behalf of ENOVA SF, (Gjølberg & Johnsen 2007) advocate a nominal WACC for renewable energy projects of 10.7 % and a real WACC of 8.2 %, assuming a long-term inflation of 2.5 %. This value will be used as the baseline discount rate for the projects discussed in this thesis, with lower and higher values set at ± 1.0 % of real WACC.

Effects on LCOE with changes in discount rates will be discussed in section 5.6.

Monetary Values

All monetary values in this thesis are stated in Euros (€), and converted to equivalent values as of January 1., 2013, to ensure that all values are compared at equal terms with regards to increased prices over time due to inflation and market mechanisms. If a source indicates a monetary value in another currency than Euros, the value is converted to Euros using the historical average exchange rate of the year of the source, and then converted to 2013-Euros ($€^{2013}$) using the so-called *Industrial Producer Price Index* (*PPI*). The reason behind using the PPI rather than using the better known *Consumer Price Index* (*CPI*), is that the CPI is regarded to be too consumer- and household-focused to give accurate results as to how monetary values in the energy industry have inflated over time. The *Industrial Producer Price Index* measures change in trading price for industrial products, with two separate sub-indices: changes in trading prices at the domestic market and at the non-domestic market, which are combined into a so-called *Total Industrial Producer Price Index*, which is used to compare prices in this thesis. (Eurostat 2012)

An average of the annual *Total Industrial Producer Price Index* in all of the 15 first European Union member countries[1] from 2003 to 2013 with 2005 as the base year is used in this thesis, to better adjust to the international nature and the Western European dominance of the European wind energy industry. The annual index values from 2003 to 2012 are given by (Eurostat 2013), while the index value of January 2013 is estimated by (Eurostat 2013) based on monthly index values by the end of 2012.

This method of converting values to desired currency before inflating to present day values, called *exchange-first indexing*, is somewhat different from *inflate-first indexing*, where values are inflated at currency-specific inflation rates before being converted to desired currency at present day exchange rates. The *exchange-first* method is a function of one constant and one variable (respectively an averaged inflation rate and an exchange rate at a given time), while the *inflate-first* method is a function of two constants (averaged inflation rate and a certain exchange rate), which leads to slightly higher variance. Nevertheless, we choose to make use of the *exchange-first* method due to the fact that this is a more reasonable alternative in cases where the exchange rate at an acquisition time impacts costs (Kaiser & Snyder 2010). We regard the wind power industry sensitive to exchange rates because of its highly international nature.

Employed conversion rates and index values are presented in Appendix 4.

1.5.4 Specialised Software

The only software used throughout this thesis, expect for conventional word processors, spreadsheet applications and graphical tools, is the so-called *Operation and Maintenance Cost Estimator* calculator (OMCE-Calculator) developed at the Energy Research Centre of the Netherlands (ECN) (Rademakers et al. 2009), used to estimate costs occurring in the Operations and Maintenance life cycle phase of wind farms. Central cost elements defined in this thesis (e.g. labour and vessel costs) are used as input values for the OMCE-Calculator, which additionally has employed certain built-in default data (e.g. spare part costs, expected installation times etc.) to supplement the calculator in estimating total O&M costs.

Use of the OMCE-Calculator is presented more thoroughly in section 3.4.2. Certain properties and default data of the OMCE-Calculator are regarded as confidential information, and will only be presented in unpublished appendices alongside this thesis.

[1] Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, The Netherlands, Portugal, Spain, Sweden, United Kingdom

2. UNDERLYING CONDITIONS

The purpose of this section is to present competing wind turbine concepts, wind farm site and turbine definitions, as well as definition of thesis scope. Costs for employed personnel and vessels utilised for construction, operation and decommissioning of a series of fictitious farms are also presented.

2.1 Competing Wind Turbine Concepts

This thesis aims to investigate costs occurring over the entire lifetime of a series of fictitious wind farms, made up of conceptual or realised concepts, presented in Table 2 and Figure 20. Bases for estimates are presented in section 2.2. Five floating concepts will be presented and compared to two bottom-fixed concepts.

Table 2: Overview of the analysed concepts (Byklum 2013; Jorde 2013; Myhr & Nygaard 2012; Myhr 2013; Weinstein 2009)

Name	TLB B and TLB X3	Hywind	WindFloat	SWAY	Bottom fixed
Developer	UMB/IFE	Statoil ASA	Principle Power	SWAY AS	-
Foundation type	Tension-Leg-Buoy (TLB)	Spar-Buoy	Semi-Submersible	Tension-Leg-Spar (TLS)	Monopile and Jacket structures
Mooring	Taut leg system (6 lines)	Catenary system (3 lines)	Catenary system (4 lines)	Vertical system (1 line)	-
Water depth	> 75 *m*	> 100 *m*	> 40 *m*	120 *m* - 500 *m*	0 *m* - 60 *m*
Substructure weight	445/521 *tons*	1 700 *tons*	2 500 *tons*	1 100 *tons* (incl. tower)	Site and depth specific
Strength	Steel mass + draft + mooring footprint	Stability	Installation + draft + stability	Steel mass + mooring footprint	Proven technology
Challenges	Installation + mooring	Steel mass	Steel mass	Installation	Water depth
Stage of development	1:40 scale test in 2013	Full-scale prototype from 2009	Full-scale prototype in 2011	1:6 scale prototype in 2011	Commercial

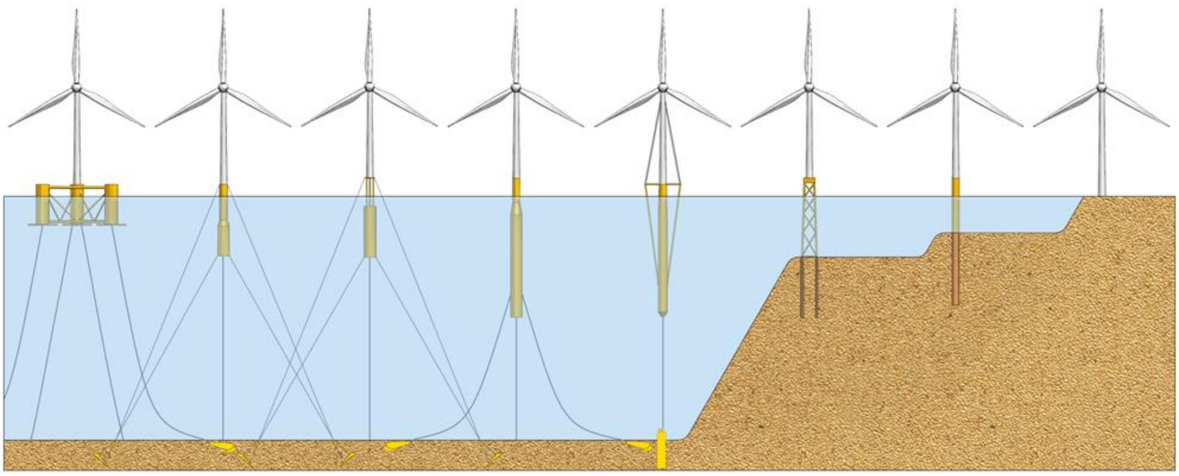


Figure 20: Illustration of the concepts, from left to right; WindFloat, TLB B, TLB X3, Hywind II, SWAY , Jacket, Monopile and onshore reference

2.1.1 TLB B and TLB X3

The two stiffness-controlled Tension Leg Buoy (TLB) concepts for wind turbine substructures have for the recent years been investigated and developed in close cooperation between the Norwegian University of Life Sciences (UMB) and the Norwegian Institute for Energy Technology (IFE). All substructure Degrees-Of-Freedom (DOF) are stiffness-controlled since two sets of inclined and taut mooring lines are attached at two heights (Figure 21), bearing strong resemblance to generic TLP concepts, however implementing some qualities of spar buoys. Many argue that the TLBs are more bottom-fixed than other floating substructures, since the vertical position is determined by the tendons, and not the water level. The concepts can be applied at water depths exceeding 75 *m* and are expected to have significantly lower steel mass compared to other substructure types at the same water depth. Accordingly, substructure material costs are assumed to be low, but mooring costs may be high relative to other floating concepts. The expected increase in mooring costs comes as a consequence of the taut mooring lines, transferring load variations due to wind and waves directly to the anchors. (Myhr & Nygaard 2012)

Figure 21: Illustration of the TLB concept (Myhr & Nygaard 2012)

The main difference between TLB B and TLB X3 is the shape of the floater in the area at the water level. The TLB B has a conical shape in this section, while the TLB X3 has transitions to three small pipes, shown in Figure 22. This reduction in cross section area will reduce the surface area where the water line surrounds the floater.

Figure 22: Models tested in wave tank. From left to right; TLB X3, Simple reference model, TLB B

In January of 2013, a two-week scale test of the TLB concepts was performed in Brest, France. The test was enabled by the *MARINET* (Marine Renewables Infrastructure Network for Emerging Energy Technologies) program, and financed through the European Commission and their *7th Framework Programme for Research and Technological Development* programme. The main objective behind the test, in addition to evaluating performance for the TLB concepts, was to obtain data intended to be published to promote further research on simulation codes for floating wind turbines. Additionally, test data will be used to validate simulation codes developed at the Norwegian Institute for Energy Technology and the Norwegian University of Life Sciences.

The overall results of the test seem promising both in regards to serve as data for development of simulation codes and general performance of the TLB concepts. Even in extreme weather simulations, the concept models indicated great substructure stability. Installation methods were also tested, and the scale models responded best to towing of a ballasted system in regards to safety and speed. Figure 23 shows photographs taken during the testing process.

Figure 23: TLB B and TLB X3 (1:40 scale) tested in Brest, France January 2013

2.1.2 Hywind

Hywind, illustrated in Figure 24 (a), is a floating wind turbine concept developed by StatoilHydro (now Statoil), which is the first full-scale floating wind turbine concept in the world. In September 2009, the Hywind pilot turbine was assembled outside Stavanger, Norway, and towed to its mooring position southwest of Karmøy, Norway, after investments exceeding €^{2013} 50 million, of which approximately €^{2013} 8 million were granted by Norwegian governmental sustainable energy enterprise Enova SF (Statoil ASA 2012). The Hywind pilot, with a draft and a hub height above water line of approximately 100 *m* and 65 *m*, respectively, is stabilised using ballast, moored using three catenary mooring lines, and is equipped with a 2.3 *MW* upwind turbine delivered by Siemens (Nielsen 2010).

The Hywind pilot has performed highly satisfactory, with capacity factors exceeding 50 % in 2011, withstanding wind speeds of over 40 *m/s* and wave heights of approximately 19 *m*. By spring 2012, the turbine had produced more than 19 *GWh*. (Rudstrøm 2012)

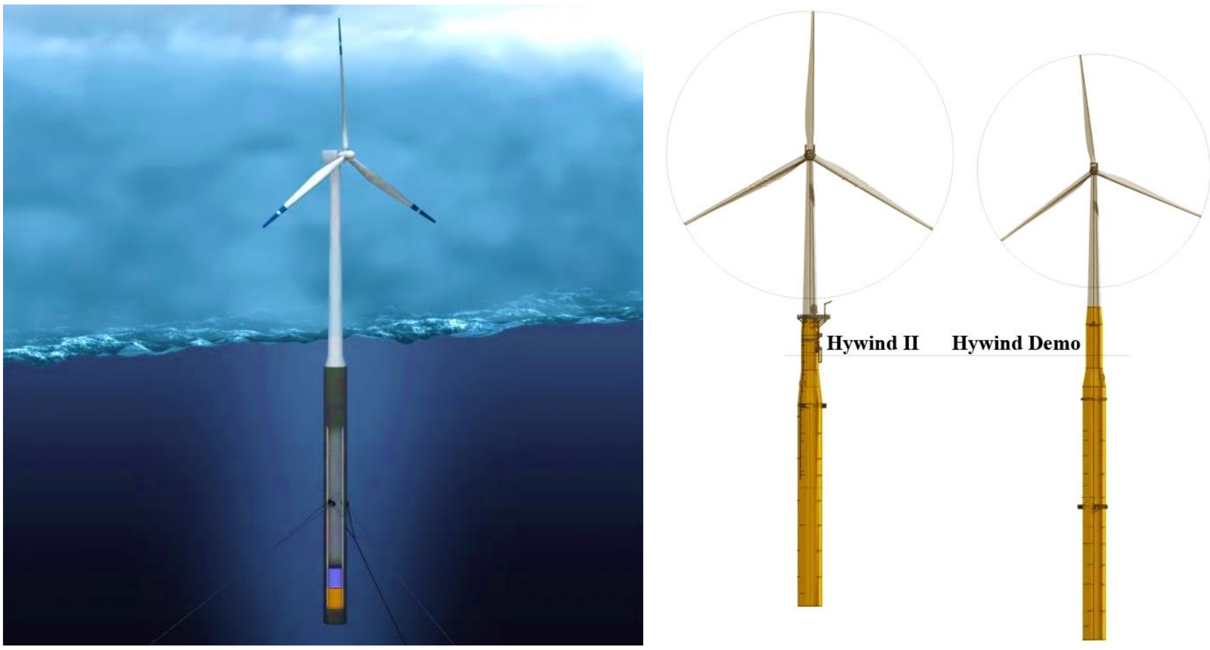


Figure 24: Left (a): Hywind (Nielsen 2010). Right (b): Hywind II vs. Hywind Demo (Bratland 2011)

According to Statoil, focusing on diminishing draft while increasing the turbine size will be key while further developing the Hywind concept, as demonstrated in Figure 24 (b) (Bratland 2011). Seeing as substructure tilt motions has had less impact on energy production than feared, experiences from the pilot turbine have indicated substructure dimensions may be reduced, leading to lower floater costs (Myhr 2013; Rudstrøm 2012).

Several further pilot projects to evaluate the performance of the further Hywind development have been proposed, with coastal regions of Maine at the American Atlantic coast as one of the more developed propositions, associated with the strong academic milieu on offshore wind power at the University of Maine. A €^{2013} 90 million wind farm consisting of four three-*MW* Hywind wind turbines has been proposed commissioned by 2016, and Statoil have already been granted approximately €^{2013} 3 million from the U.S. Department of Energy. (Turkel 2013)

2.1.3 WindFloat

The WindFloat concept, developed by Marine Innovation & Technology and commercialised by Principle Power, consists of a semi-submersible, three-legged platform with a draft considerably less than its competitors, designed to carry one upwind turbine in the region of 3-10 *MW* in ocean depths greater than 40 *m*. Each of the three legs contain ballast water, which both improves static stability and dynamic stability through an Active Heave Compensation system, dampening heave motions, ensuring stability through mutual distribution of ballast water according to wind direction and magnitude. Due to shallow draft and high stability, it is possible to build WindFloat turbines in a dry dock and tow them to site using tug boats, but the high stability is made possible through use of large quantities of steel, leading to severe material costs. An illustration of the concept is shown in Figure 25. (Principle Power 2011)

Figure 25: WindFloat illustration (Principle Power 2012)

The WindFloat pilot turbine was built and towed to site off the coast of Portugal during fall of 2011, consisting of a 2 *MW* turbine delivered by Danish turbine producer Vestas (Shahan 2011). Similar to Hywind experiences, the WindFloat pilot has responded promisingly well to weather conditions and motions, in line with simulations. The pilot project, costing an estimated €^{2013} 23 million, had generated approximately 3 *GWh* during its first year of operation (Maciel 2012).

2.1.4 SWAY

SWAY is a patented floating wind turbine concept developed in Norway by SWAY AS, illustrated in Figure 26. SWAY is stabilised through a combination of self-stabilising ballast and TLP technology, and anchored to the seabed using a suction anchor and a pipe marginally shorter than the water depth, in order for tension to occur in the anchoring system. As opposed to more conventional concepts, the SWAY concept's nacelle does not rotate around a bearing at the top of the tower. Instead, the entire system is designed to rotate around a submerged bearing in the bottom of the structure, which makes strengthening of the tower through a tension rod system possible. SWAY is designed to carry a down-wind rotor. (SWAY AS 2012)

Figure 26: SWAY illustration (European Wind Energy Association 2009b)

SWAY is designed to carry turbines in the region of 2.5 - 5 *MW* (SWAY AS 2012). A main feat of the SWAY concept is the overall material consumption, expected to be significantly reduced relative to those of competing pilot projects when adjusted for turbine capacity (Borgen 2010).

In 2009, SWAY AS were authorised by the Norwegian Water Resources and Energy Directorate to erect a pilot turbine west of Karmøy, Norway, and in 2011 a 1:6 scaled pilot turbine was unveiled in Hjeltefjorden, Norway (Amelie 2011). The pilot turbine sank during harsh weather conditions in late 2011, but was later salvaged and reinstalled during the spring of 2012 (Steensen 2011; SWAY AS 2012).

2.1.5 Floating Concept Summary

As discussed by (Butterfield et al. 2005), floating substructures may be viewed as a combination of three main stabilisation concepts: ballast stabilised concepts, mooring line stabilised concepts and buoyancy stabilised structures. Figure 27 shows the relation between stabilisation methods for the concepts investigated in this thesis.

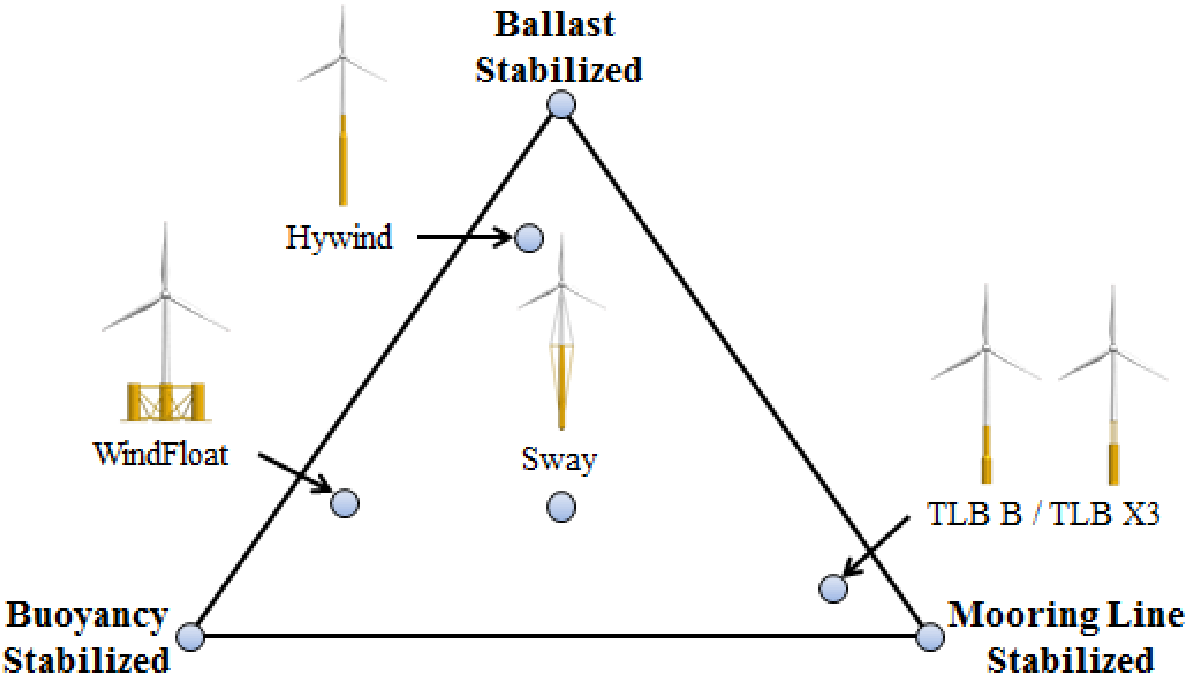


Figure 27: Floating substructure stability triangle

As indicated, the evaluated structures are stabilised through varying methods. The Hywind concept is mainly stabilised through consumption of large ballast masses, and accordingly, the mooring system does not have to cope with any significant excess buoyancy. However, the mooring system is expected to provide some heave stability, but is only intended for horizontal station keeping. The draft of a Hywind concept wind turbine able to carry a 5 *MW* turbine is expected to be approximately 80 *m* (Byklum 2013).

The WindFloat concept is as Hywind expected to be highly stable, and is stabilised through distribution of buoyancy elements and ballast. As for the Hywind concept, the mooring system for the WindFloat concept is expected to be mainly for horizontal station keeping. The draft of the WindFloat is expected to be approximately 25 *m* (Aubault et al. 2010).

The TLB concepts experience tremendous excess buoyancy, leading to taut mooring lines keeping the concepts almost completely fixed both vertically and horizontally. The concepts are expected to have drafts of 50 *m* (Myhr & Nygaard 2012).

The SWAY concept is indicated to rely on a combination of all of the three stabilisation systems, and is expected to have a draft just shy of 100 *m* (Jorde 2013).

2.1.6 Bottom-fixed References

Most of the commercial bottom-fixed wind farms operating as of 2013 are based on monopile foundations, while gravity-based structures are predominantly used for the rest of the bottom-fixed installations world-wide. However, jacket structures are, while currently only installed in small quantities, a commercially feasible solution for water depths exceeding preferred depths for monopiles and gravity-based structures, due to abilities to carry heavy structures and resist challenging wave loads, in addition to low material costs. (European Wind Energy Association 2011)

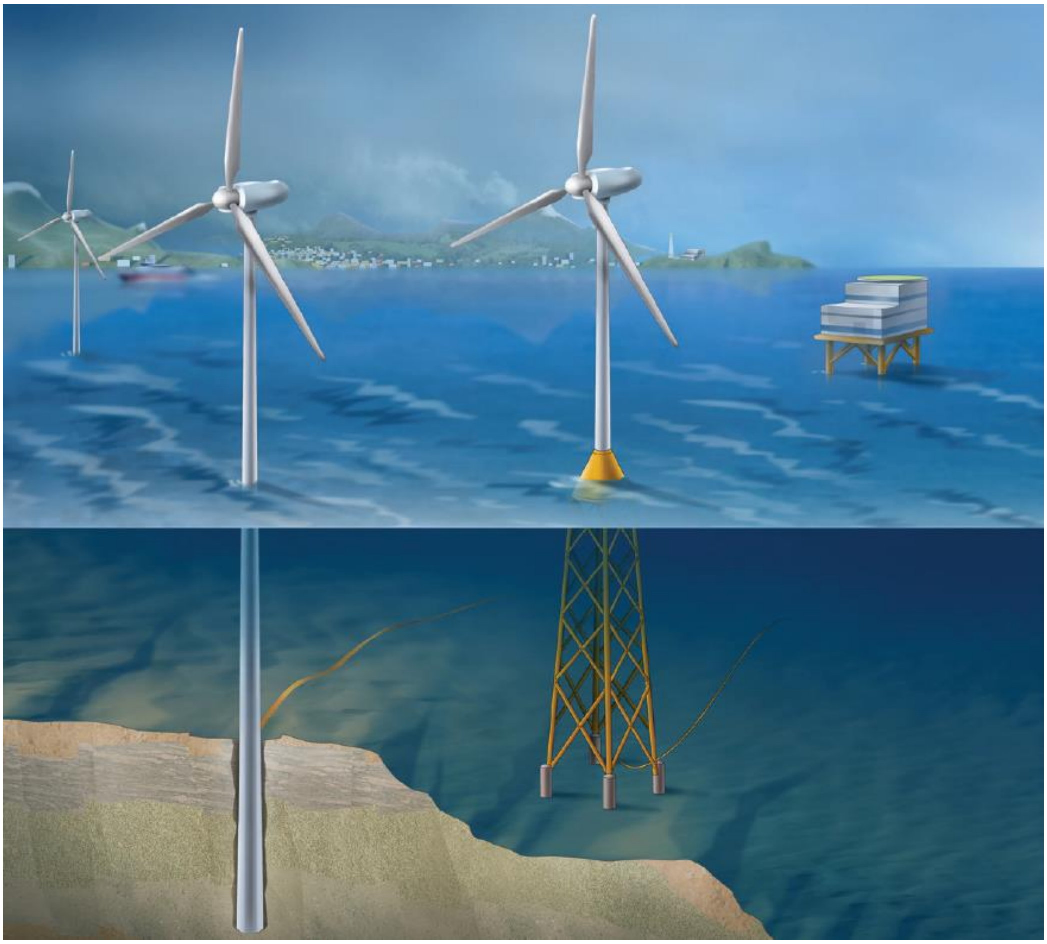


Figure 28: Illustration of monopile- and jacket-based wind turbines (Hernando & Svendsen 2012)

For this thesis, the floating concepts will be evaluated relative to bottom-fixed references, both monopile substructures and jacket substructures, respectively illustrated on the left and right of Figure 28. Monopile structures are the most commonly used substructures for bottom-fixed wind turbine concepts, but are poorly suited for water depths exceeding approximately 30 *m* because of insufficient strength and stiffness (Borgen 2010). Accordingly, generic monopile structures and jacket structures will be evaluated for depths of 30 *m*.

Note that throughout this thesis, the term monopile refers to both the pile driven into the seabed and to the transitional piece connecting the pile to the turbine tower, in addition to secondary structures, that together make up a complete substructure.

2.2 Common Conditions

The intention of this section is to present conditions that are shared by all of the investigated concepts. These conditions include the general definition of the wind farm, with site parameters such as distance, weather- and soil conditions. Also included are turbine and scope definition assumed to be identical for all investigated concepts.

2.2.1 Wind Farm Definition

This thesis discusses fictitious scenarios with wind farms consisting of 100 wind turbines for each of the seven chosen wind turbine concepts, resulting in wind farm capacities of 500 *MW* given a turbine size of 5 *MW*.

The benchmark distance from shore to the farm is initially set to 200 *km* for all investigated concepts, at water depths of 200 *m* for floating concepts and 30 *m* for bottom-fixed concepts. The wind farm is put up as a square formation (10 x 10) with an inner distance between each turbine of 1 *km*, as shown in Figure 29. The diagonal of the wind farm is thought oriented in the prevailing wind direction at site. Throughout the thesis, impact on levelised costs of energy by variations on parameters such as farm size, water depth, offshore distance and project life span will be evaluated.

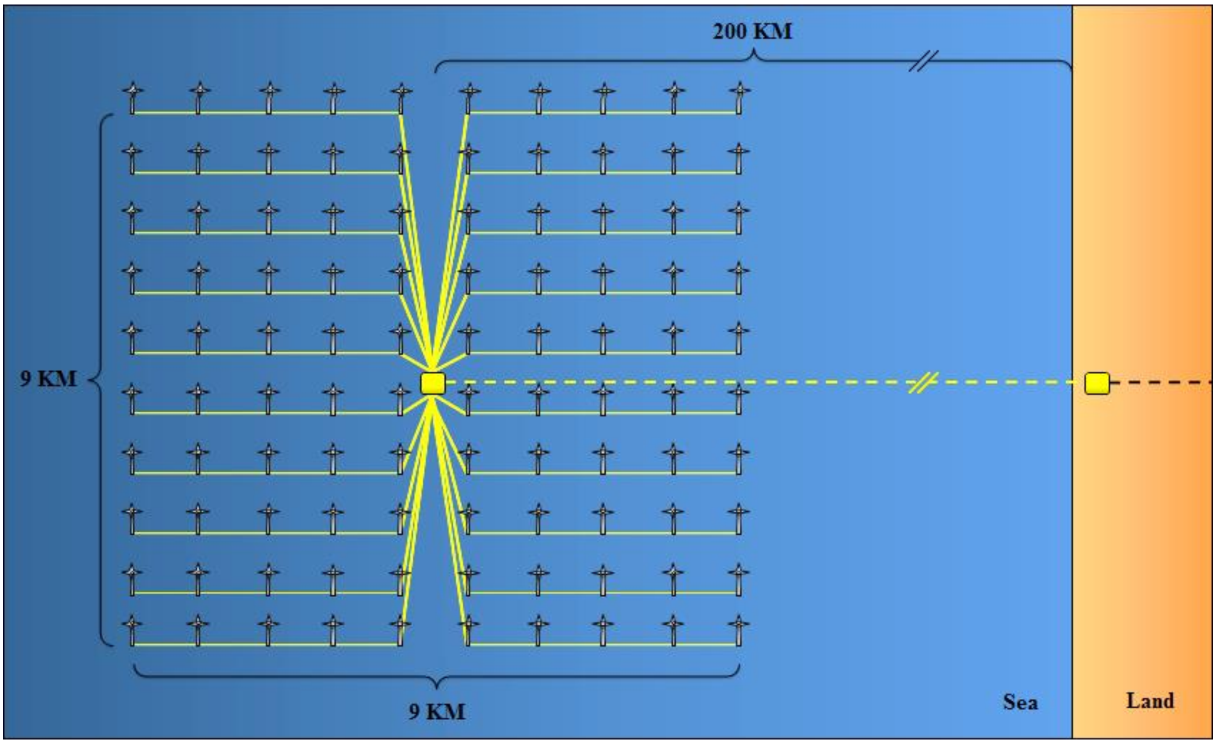


Figure 29: Information about the fictive benchmark wind farm with regards to distances in our scenarios

General wind farm data for the fictive benchmark wind farm are presented in Table 3.

Table 3: Site assumptions for benchmark wind farm case

General wind farm information		
General	Years of development	2013 – 2018
	Commissioning year	2018
	Project Life Span	20 years

Table 3 continued: Site assumptions for benchmark wind farm case

General wind farm information		
Technical Data	Number of wind turbines	100 units
	Size of wind farm	500 *MW*
	Size of offshore substation	500 *MVA*
	Turbine type	Generic 5 *MW*
	Water Depth (MSL) for the floating concepts	200 *m*
	Water Depth (MSL) for the bottom-fixed concepts	30 *m*
	Distance to nearest construction and operations port	200 *km*
	Average wind speed at hub height	10 *m/s*
	Site soil conditions	Medium clay

Hub height mean wind speed is set to 10 *m/s*, and speed distribution is assumed to follow the Weibull distribution presented in Figure 30, derived from (Bierbooms 2010).

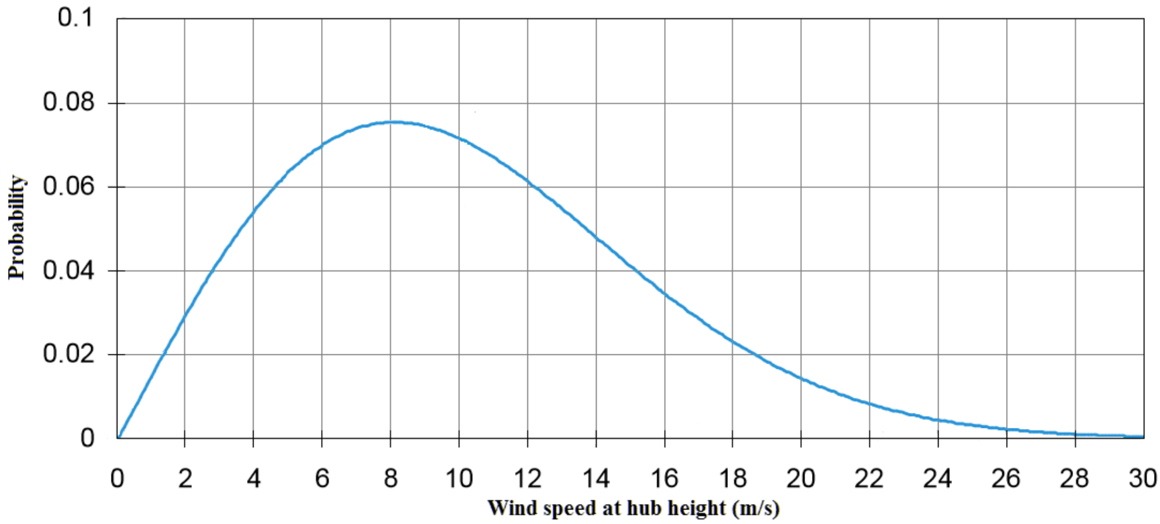


Figure 30: Wind speed distribution at site, derived from (Bierbooms 2010)

No exact, geographical location for the farm is set, but the farm is thought to be positioned at a generic, Northern European site. Weather conditions at sea level are presented in Table 4, based on average sea state and wave data from the North Atlantic region (Faltinsen 1990). The soil conditions of the site are assumed to be homogenous clay of medium density.

Table 4: Sea state and wave data: North Atlantic region, derived from (Faltinsen 1990)

Sea state	Percentage of time	Significant wave height (*m*)	
		Range	Mean
0-1	0.70 %	0.0 – 0.1	0.05
2	6.80 %	0.1 – 0.5	0.30
3	23.70 %	0.5 – 1.3	0.88
4	27.80 %	1.3 – 2.5	1.88
5	20.64 %	2.5 – 4.0	3.25
6	13.15 %	4.0 – 6.0	5.00
7	6.05 %	6.0 – 9.0	7.50
8	1.11 %	9.0 – 14.0	11.50
>8	0.05 %	>14.0	>14.00

2.2.2 Turbine Definition

All concepts are assumed to be deployed using generic 5 *MW* turbines. To serve as basis for these turbines, the theoretical National Renewable Energy Laboratory (NREL) offshore 5 *MW* baseline turbine is utilised, a conventional three-bladed upwind turbine developed to support concept studies for offshore wind technology, based on specifications of the commercially available REpower 5M turbine made by German turbine manufacturer REpower Systems. The NREL 5 *MW* turbine represents a typical utility-scale land- and sea-based megawatt turbine, also suitable for deployment in deep waters. (Butterfield et al. 2009)

Physical properties of the NREL 5 *MW* turbine are utilised when needed, i.e. when finding capacity requirements for lift vessels and turbine cost distributions. Total turbine component costs are evaluated on basis of generic sources with few direct interests in turbine production.

Seeing as the concept substructures rise a certain height over the water line, the turbine towers will be shorter than the indicated hub height by the total substructure above-MSL height, for most concepts 10 *m*. This reduces total tower height for the towers deployed in our scenarios in accordance with information provided by (Butterfield et al. 2009).

Accordingly, physical turbine properties of Table 5 come from calculations made in unpublished work by Raadahl and Vold, based on data from Butterfield et al (2009). Electrical properties are based on 2011 data provided by REpower Systems. (Butterfield et al. 2009; Raadahl & Vold 2013; REpower Systems 2011)

Table 5: Properties for the generic 5 MW Turbine, derived from (Butterfield et al. 2009; Raadahl & Vold 2013; REpower Systems 2011)

Generic 5 *MW* Turbine	
Rated power	5 *MW*
Rotor diameter	126 *m*
Hub Height	90 *m*
Rotor mass	110 *ton* (of which 54 % steel)
Nacelle mass	240 *ton* (of which 82 % steel
Tower mass	250[1] *ton* (of which 93 % steel)
Rated speed	14 *m/s*
Operational wind speed limits	3.5 *m/s* (cut-in) 30 *m/s* (cut-out)
Generator type	Double-fed, asynchronous, 6-pole

1) Depending on concept

The turbine is assumed to include a pitch control system (Butterfield et al. 2009). A crane capable of lifting replacement components weighing up to approximately 2 *tons* is expected to be integrated in the turbine nacelle, supported by actual layout of the Repower 5M turbine (REpower Systems 2011). Additionally, a davit crane is assumed to be positioned near the base of the tower for each concept, enabling possibilities to hoist replacement components from service vessels.

2.2.3 Energy Production

To better understand the nature of electricity generation of a wind turbine, it is important to note that a wind turbine will not produce its rated power at all times, depending on weather conditions and mechanical and electric losses.

Capacity Factor

A wind turbine requires a certain wind speed, the so-called cut-in speed, to start to produce electric power, and will not produce its rated power before the wind speed exceeds a given value, known as the turbine's rated wind speed. When wind speeds increase, the *power control unit* of the wind turbine constricts the power output from the turbine to ensure that energy production does not exceed the power rating, and in order to reduce chances of damages on the turbine, the turbine will continue to produce it's rated power until the wind speed reaches the *cut-off speed*, the maximum allowed operational wind speed for the wind turbine. Figure 31 shows the turbine power distribution curve for a REpower 5M offshore turbine, with a cut-in speed of 3.5 *m/s*, a rated speed of 14 *m/s* and a cut-off speed of 30 *m/s*.

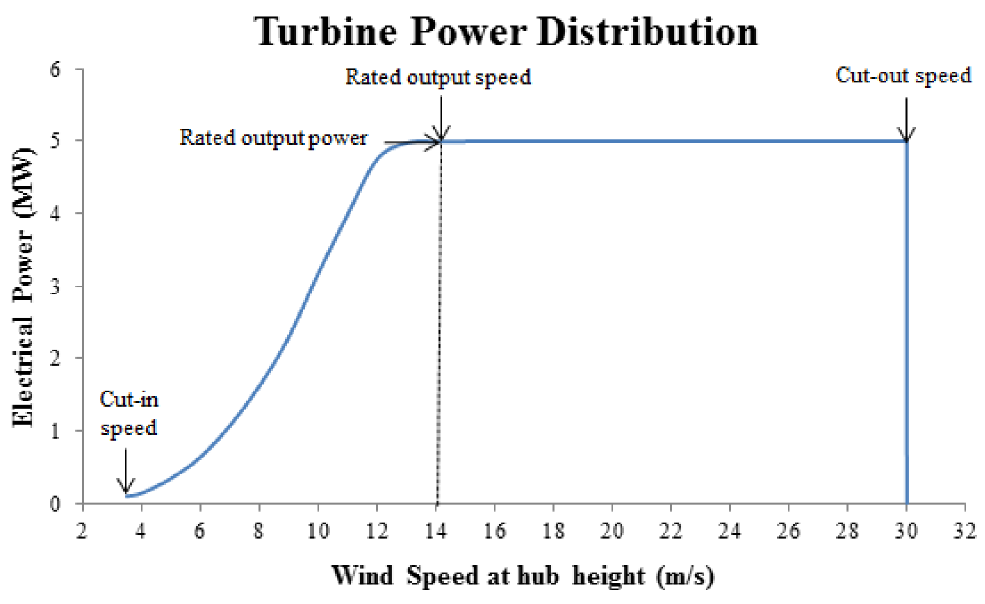


Figure 31: Turbine power curve, derived from (REpower Systems 2011)

Calculations performed by German physicist Alfred Betz states that the maximum energy which can be harvested from the wind is given by the following relation (Wildi 2006):

$$P_a = B \cdot v^3 \qquad \textbf{(5)}$$

Where:
P_a *denotes the maximum power harvestable per square meter* (W/m^2)
v denotes the wind speed in m/s
B denotes the so-called Betz constant ($B \approx {}^{16}/_{27}$).

The Betz constant denotes that it is possible to harvest approximately 60 % of the total kinetic energy of the wind, which is done when the turbine blades are regulated so that the incoming wind speed is approximately three times higher than the wind speed directly behind the turbine blades (Danish Wind Industry Association 2011a).

According to this formula, a 50 % reduction in wind speed will lead to a nearly 88 % decline in harvested power. This corresponds with the power curve shown in Figure 31, where the turbine hits 5 *MW* of produced power near wind speeds of 14 *m/s*, with production of only 13 % of this on speeds of 7 *m/s*.

As important as data on turbine performance is data on site wind conditions, as turbine and site wind data combined can give accurate data on anticipated turbine energy production. On a year-to-year basis, wind conditions on a specific site tend not to differentiate much, but conditions vary throughout the year. In winter time, when the demand for electricity traditionally is at its greatest, windy conditions and high air density from colder temperatures lead to slightly higher turbine output. (European Wind Energy Association 2009a).

When evaluating wind electricity production, an important figure is the so-called *capacity factor*. The capacity factor is defined as the percent ratio between realised or anticipated energy production and theoretical production if the turbine were to operate at rated power at any given moment through a year, and is influenced by production losses due to the *wind climate*. The term wind climate treats not only wind speeds, but also turbulence, wind shear (wind speed differences between the lower and the upper part of the rotor) and extreme winds and gusts. Note that capacity factor alone is no good measurement for the profitability of a certain wind turbine at a certain cite, as the number is more a measure of efficiency than productivity. By manipulating turbine design and generator size to more effectively operate at lower wind speeds, it is possible to enhance the capacity factor, but in turn reduce productivity. Increase in generator size does not necessarily contribute to a proportional increase in total turbine cost, so wind turbine designers often incorporate larger generators to better profit from those days when wind speeds are high, leading to average capacity factor decline, but often greater productivity and thus greater profitability (European Wind Energy Association 2009a).

By reason that capacity factors depend on several factors, direct comparison of experienced capacity factors between wind farms without consideration for turbine data is not a good measure for either wind conditions or site profitability, as comparisons should only be executed when turbine conditions are similar. Figure 32 shows the anticipated capacity factor in Northern European waters for a REpower 5M turbine, hub height at 100 MAMSL (Kjeller Vindteknikk / Norwegian Water Resources and Energy Directorate 2010).

The goal for every wind energy producer is to minimise the total life cycle cost per unit of output energy. Seeing as the available wind energy is both free and to a certain degree unlimitedly available, a turbine designer will prefer a design that limits both efficiency and also life cycle energy productivity to a design that is technically superior in terms of efficiency and productivity, as long as the technically inferior solution lowers the levelised life cycle costs. (European Wind Energy Association 2009a)

Based on expected projections of offshore wind energy capacity factors and experienced capacity factors of floating wind turbine pilot projects, a baseline capacity factor of 53 % is assumed in this thesis (Open Energy Info 2013). Low and high scenarios are set to ± 3 %. Changes in LCOE with changing capacity factors will be discussed later in the thesis.

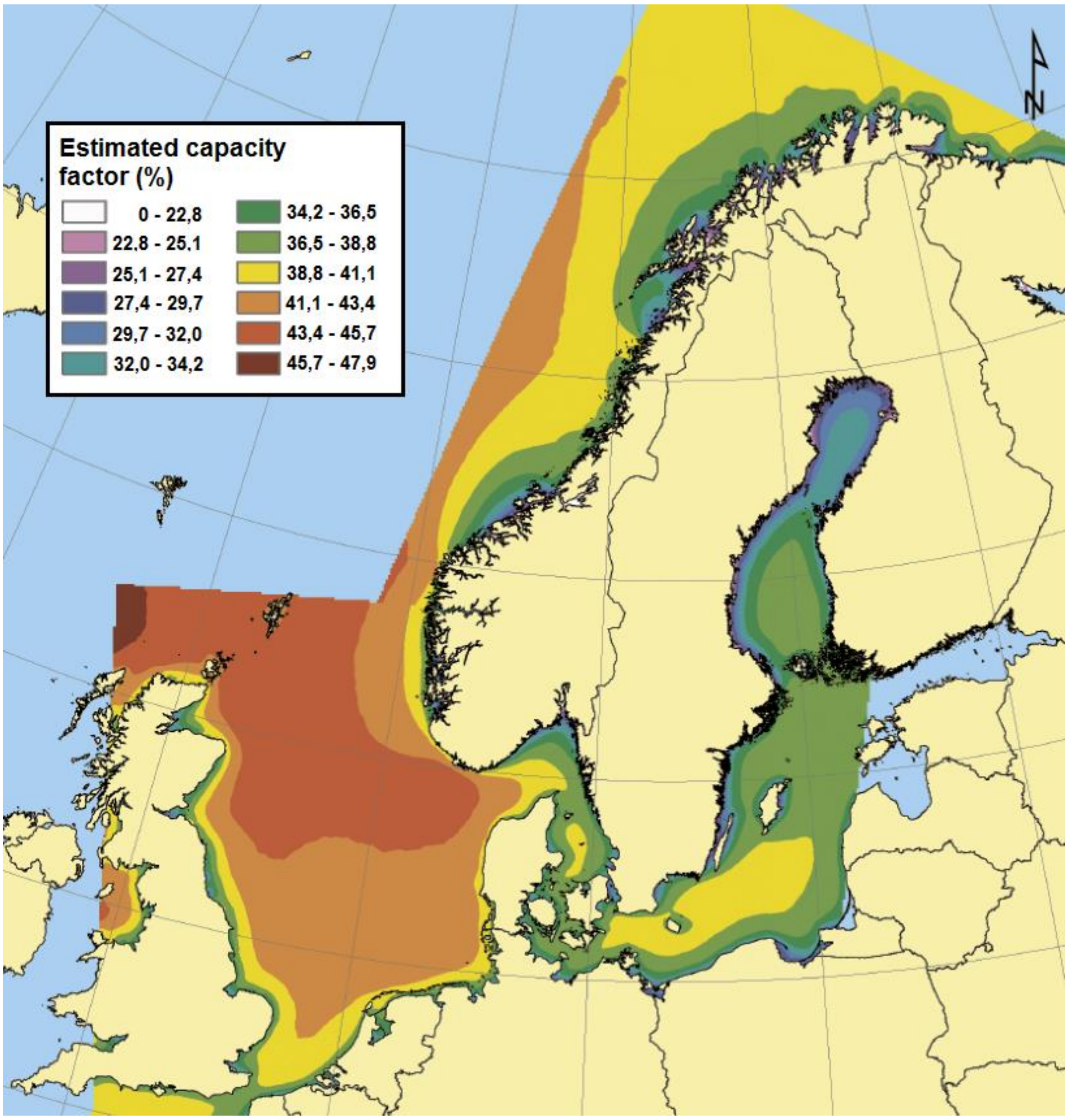


Figure 32: Capacity factors at Northern European sites, based on REpower 5M (Kjeller Vindteknikk / Norwegian Water Resources and Energy Directorate 2010)

Load Factor

The net output on the electricity grid is not only affected by wind climate condition losses, also a series of other losses from external and internal effects have negative impact on electricity generation. We may divide these losses into electrical array losses, aerodynamic losses, wind farm availability and other losses (European Wind Energy Association 2009a). Subtracting these losses from the capacity factor gives the so-called *load factor*, which is the ratio between realised or anticipated grid output and theoretical production (Howard 2012).

The relation between theoretical production, capacity factor and load factor is shown in Figure 33.

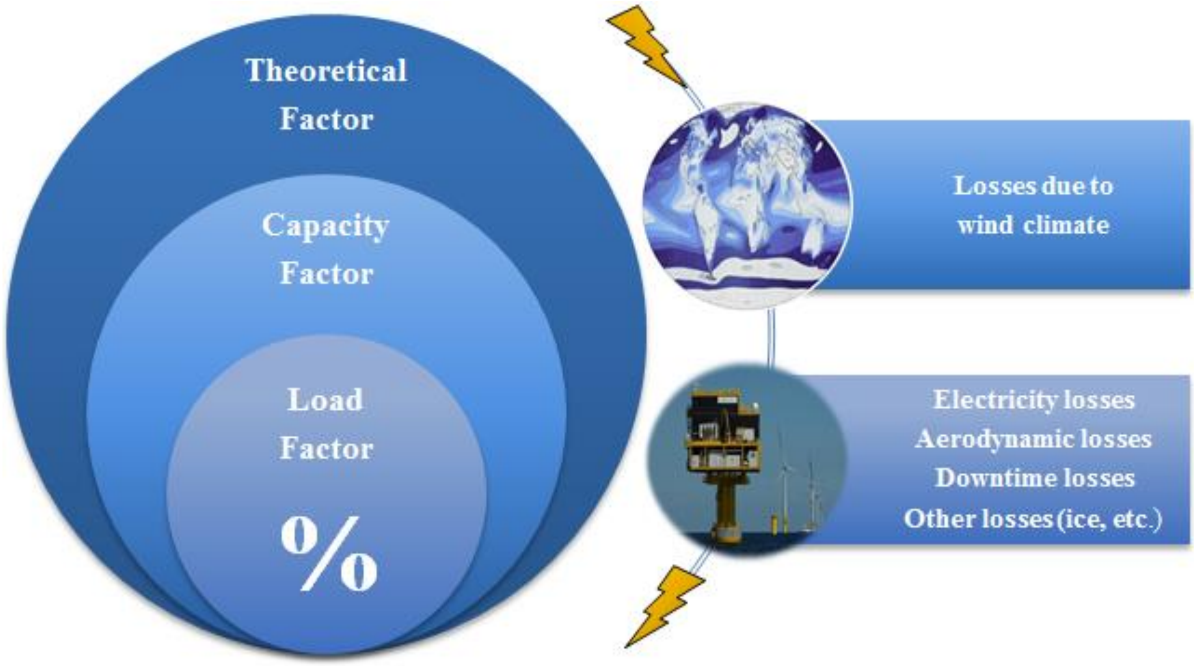


Figure 33: Relation between theoretical production, capacity factor and load factor

Electrical Losses

Electrical losses denote ohmic losses dissipated as heat in the inter-array cables, export cables and substation. The losses vary with farm layout, voltage levels and cable length, and discussions in section 3.2.4 and Appendix 7 indicate total electric losses to be approximately 1.8 %. However, these losses are estimated on simplified grounds, and may be somewhat uncertain, as other factors not discussed in this thesis may influence losses.

Aerodynamic Losses

Aerodynamic array losses occur when wind turbines shadow one another in a wind farm, leaving less energy in the wind downstream of each turbine. Both mean wind speed, turbulence intensity, turbine spacing and rotor diameter affects the aerodynamic array losses. As the turbines are located closer to each other, smaller relative distance between turbines progressively disallows the wake effects to be dissipated before the wake effects from the next turbines are encountered.

(European Wind Energy Association 2009a) estimate these losses may account for 5 - 10 % of the theoretical output. Based on a turbine spacing of nine times the rotor diameter in the prevailing wind direction and a wind speed of 10 *m/s* at 100 *m* above mean sea level, (BVG Associates 2012) estimate the these losses to on average be 7.75 % for a 5 *MW* wind turbine farm. This turbine spacing is lower than the ones used in our wind farm definitions, leading to assumptions that an average loss percentage of 7.0 % may be estimated for our calculations.

Wind farm Availability

Wind farm availabilities denote the average percentage of time the wind turbines may operate, involving downtime from mechanical failure, maintenance etc. The wind farm availability includes the wind turbine, inter-array and export cables and substation availability. In general, wind farm availabilities are often assumed between 95 % (Clayton et al. 2011) and 98 %

(European Wind Energy Association 2009a). Positioning of the thesis far offshore, and harsh weather conditions affect the wind farms defined in this thesis, and general availability for benchmark wind farms is in section 3.4.3 simulated to be approximately 90 – 96 %, with baseline figures at approximately 94 %, with minor differences between floating and bottom-fixed concepts from stochastic simulations.

Other Losses

A series of other losses affect the actual performance of the wind farm with respect to theoretical power output. We may for simplicity divide these other effects into losses from hysteresis, losses from power curve degradation and losses from diminishing of power performance (BVG Associates 2012).

Hysteresis losses are losses coming from rapid changes in wind direction to such an extent the yaw mechanism of the wind turbine may not sufficiently and efficiently keep up with. Power curve degradation losses come from the fact that turbine power curves are constructed from ideal data, and do not sufficiently depict real world conditions (European Wind Energy Association 2009b). These losses are estimated to 1 % (BVG Associates 2012; Clayton et al. 2011; European Wind Energy Association 2009a).

Diminishing of power performance through soiling effects, and in particular so-called in-cloud icings have potentially severe negative effects on wind turbines. Not only does ice on the structure pose as a potential danger to anyone or anything at site through ice shedding, ice loads may also increase fatigue and failure risks from vibrations and resonance. More important to energy production in Northern European waters, icing on rotor surfaces could also impair aerodynamic abilities, resulting in poorer turbine performance (Haaland 2011). When taking soiling from dust, corrosion etc. into consideration, power performance losses have been estimated to 2 % (European Wind Energy Association 2009a). Combining these with hysteresis and power curve degradation losses sets the total *other losses* to 3 %.

Load factor calculation

The total load factor for the benchmark wind farms rely both on factors that go beyond the scope of this thesis, e.g. aerodynamic losses, and factors that will be discussed more profoundly throughout the thesis. The baseline load factor used for floating concepts in this thesis is presented in Table 6.

Table 6: Baseline load factor

Energy Production	
Theoretical production (*MWh/MW/yr*)	8 760
Capacity factor	53.0 %
Net load factor	44.0 %
Wind farm availability	93.8 %
Aerodynamic array losses	7.0 %
Electrical array losses	1.8 %
Other losses	3.0 %
Net energy production (*MWh/MW/yr*)	**3 859**

2.2.4 Scope and Viewpoint Definition

When evaluating costs for offshore wind power projects, it is important to bear in mind that several company types may be involved in the supply chain from realising a turbine concept to erecting a commercial, offshore wind farm. The European Wind Energy Association operates with eight different company types involved in offshore wind supply chains (European Wind Energy Association 2011):

- **Turbine manufacturers -** designs and supplies turbines. Examples: Vestas, REpower, Siemens
- **Structural manufacturers -** manufactures substructures for wind turbines and possibly offshore substations. Examples: Aker, Smulders, Burntisland Fabrications
- **Electrical equipment manufacturers -** designs electrical systems and supplies electrical equipment for offshore and onshore use. Examples: ABB, Siemens
- **Marine contractors -** installs wind turbines, substructures, substations and cables. Examples: A2SEA, MPI
- **Cable suppliers -** supplies both export and array cables. Example: Nexans, Prysmian
- **Cable installers -** Marine contractors specialised in cable installation niche. Examples: Technip, Visser & Smit
- **Engineering, Procurement, Construction and Installation contractors -** larger firms or ventures from above mentioned categories, responsible for broader parts of the supply chain. Acquires necessary materials for production, and produces, transports and installs the product in exchange for a fixed price. Examples: ABJV, MT Højgaard, Subsea7
- **Port operators -** provides manufacturing and assembly properties, operation and maintenance base

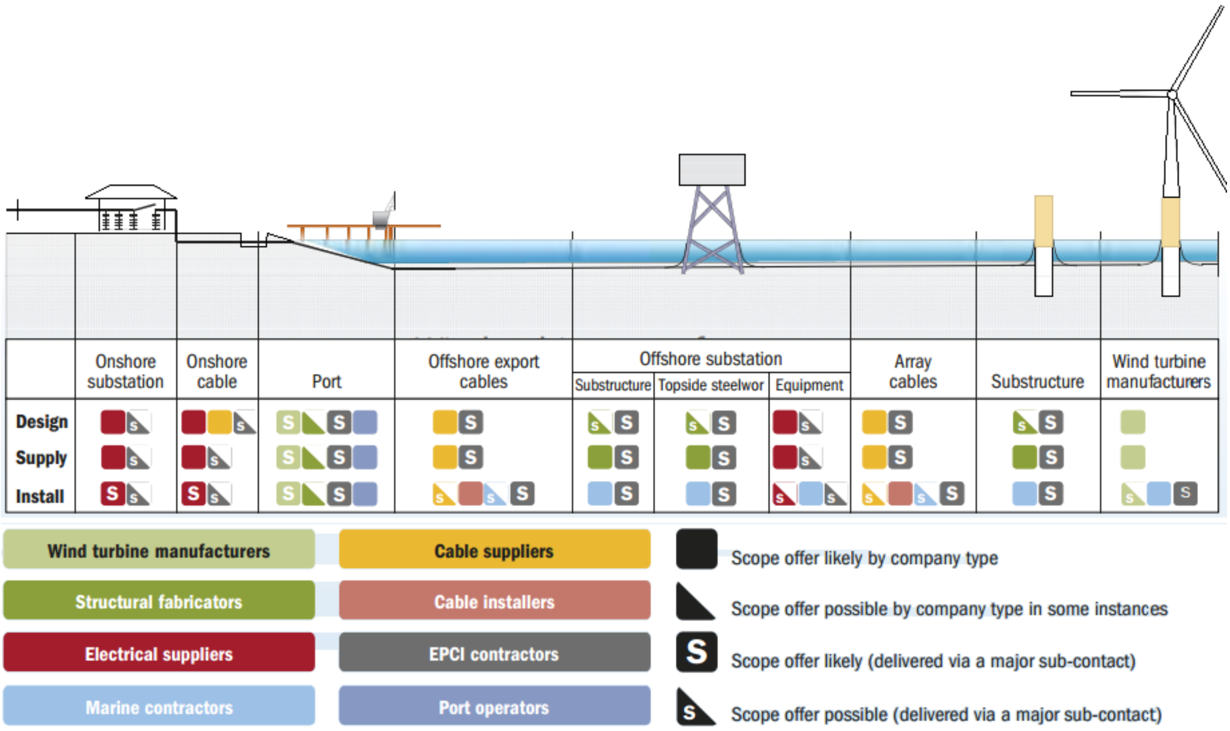


Figure 34: Company types participating in wind farm supply chain (European Wind Energy Association 2011)

It seems clear that some companies, especially larger multidisciplinary firms, may be able to perform several parts of the supply chain, and that some parts of the chain may be performed by several company types, with turbine design and turbine supply as the main exception. Supply chain scopes are demonstrated in Figure 34, while locations of some of the key players within the existing, bottom-fixed wind energy industry are presented in Figure 35 (European Wind Energy Association 2011).

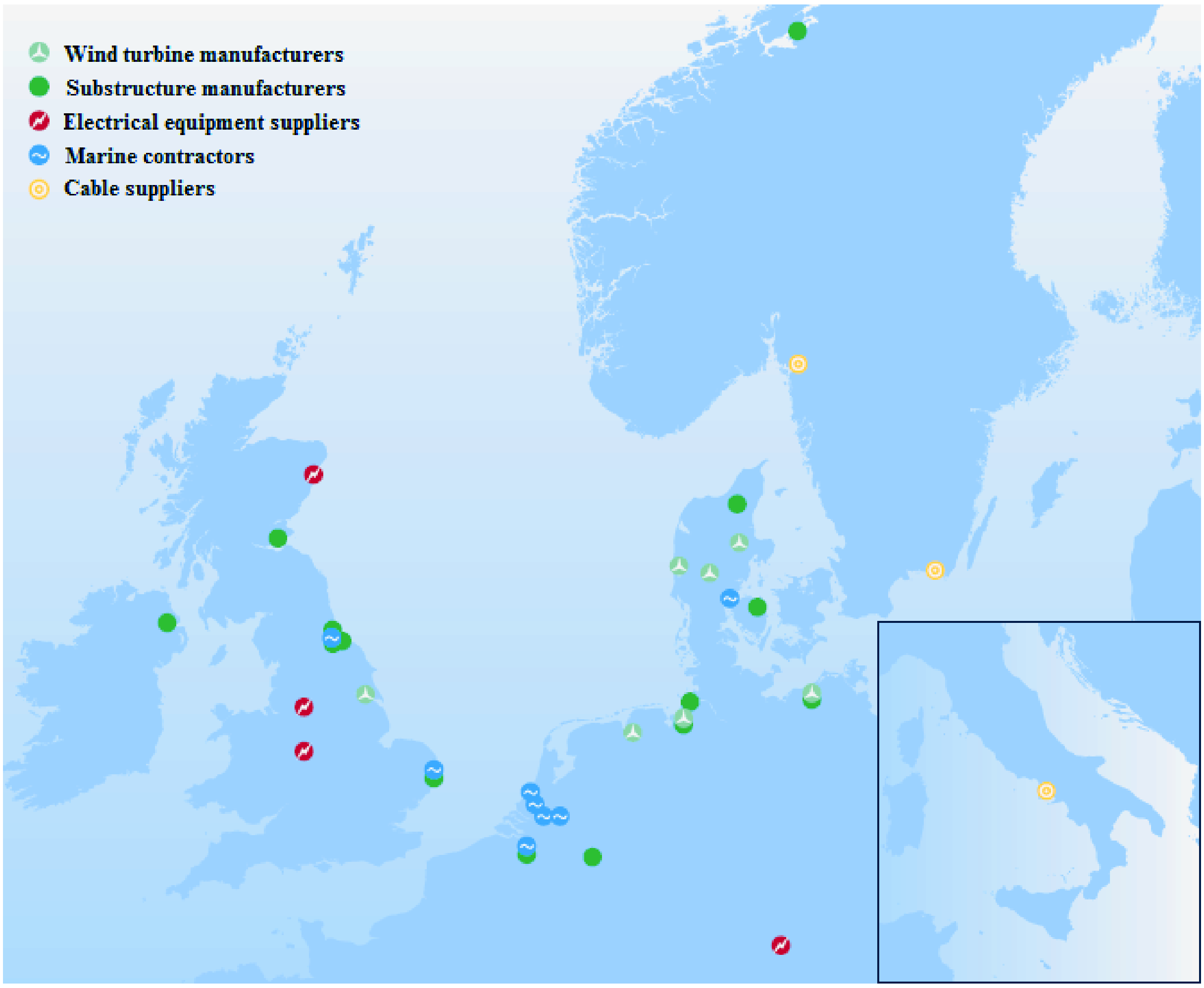


Figure 35: Location of key players within the European wind energy industry (European Wind Energy Association 2011)

When evaluating total life cycle costs for a series of fictive wind farms, it is important to decide from which point of view this should be done. We have chosen to view the situation from the eyes of a company rich in both capital and general offshore experience, which, if desirable, enables possibilities to handle large parts of the supply chain within the company, such as production of mechanical components and some or all parts of installation and maintenance of a wind farm through acquisition of production facilities and vessels. This way, highly specialised operations such as turbine and electrical equipment supply are handled by specialists.

2.3 Other Conditions

The purpose of this section is to present some of the cost drivers related to installation, operation and decommissioning of the wind farm. We present commodity costs, evaluated personnel cost, and finally utilised vessels and their corresponding costs.

2.3.1 Commodity and Personnel Costs

Costs on certain commodities are expected to contribute to large portions of the total capital costs of a generic wind farm. The dominant costs are expected from materials employed to construct the wind turbines, which are mainly made of steel. Additionally, fuel costs contribute to costs for installation, operation and maintenance and decommissioning of the wind farm.

Steel Costs

A majority of total the total material costs from turbines and substructures comes from steel consumption, and given the severe mass consumptions per unit, the concept material cost depend greatly on worldwide steel prices. For this thesis, costs for steel quality S355 are employed. These prices are volatile, but present day per *ton* prices from a selection of Chinese suppliers for S355 plates with thicknesses of 30 - 100 *mm*, widths of 1 - 4 *m* and lengths of 6 - 10 *m* range between approximately €^{2013} 450 - 1 100 *Free on board*, meaning excluding freight (Alibaba 2013b).

For baseline calculations for this thesis, a bulk price of €^{2013} 1 000 per *ton* is set. This price is based on average estimates from Chinese suppliers, and includes a 25 % addition on plate prices to account for surface- and corrosion treatment of the members (Tech-wise AS 2001). Added is also a freight rate, estimated by *The Steel Index* to be approximately €^{2013} 21 per *ton* freighted by sea from China to Europe (The Steel Index 2013).

It is assumed that these prices include coarse dimensioning of the plates, e.g. plates will be produced and shipped in specified, requested dimensions best suited for large-scale production in adequate production facilities.

To account for volatility, low and high case steel prices are estimated from higher and lower values indicated by Chinese suppliers, and are set at ± 40 % of the baseline bulk price, respectively.

Fuel Costs

Relevant fuel costs when evaluating offshore vessels are costs of bunker fuel, which is in reality a common definition on all subcategories of fuel employed by seagoing vessels. Fuel costs for this thesis will be based on Marine Gas Oil (MGO) transaction prices in Rotterdam. Bunker fuel prices are extremely volatile, and could vary severely over time, as indicated in Figure 36, where European bunker fuel prices and bunker fuel price developments from January 2006 to January 2012 are shown. Please note that the depicted graph does not show actual price development of MGO, but rather a weekly weighted average of bunker fuel prices based on several subcategories of fuel. Resultantly, the graph is not an indicator of MGO prices, but may act as an indicator of MGO price volatility.

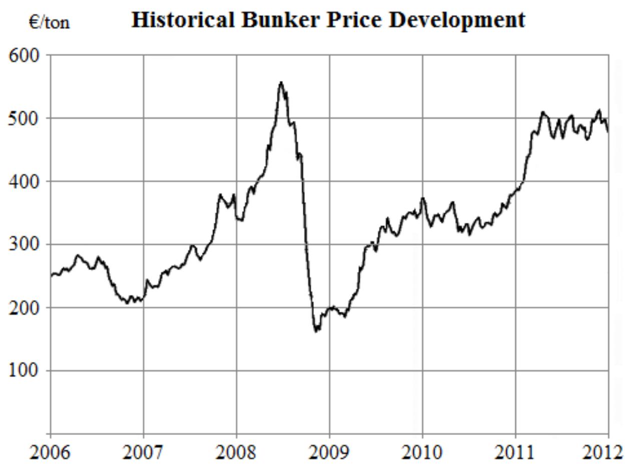


Figure 36: European price development of bunker fuel, 2006 - 2012, derived from (Hoag 2011)

Fuel costs employed in this thesis are assumed to be approximately €^{2013} 640 per *ton*, based on mid-April averages of delivered MGO at the port of Rotterdam (Bomann-Larsen 2013; Bunker Index 2013). This per *ton* cost is assumed to include all surcharges and fees.

Even though bunker fuel prices tend to vary, it is assumed that fuel costs account for percentages of the total vessel costs so small that these variances will not be further discussed. The relation between fuel costs and total vessel costs are presented in section 2.3.2. Based on relations between day rates excluding fuel and expected fuel consumption, the PSV seems to be the most sensitive vessel to fuel cost variations. However, a 15 % real increase in fuel cost leads to an approximate 6 % increase in day rates, and such variations are expected to be conservatively included in evaluations of the results corresponding to low and high cases of vessel costs.

Personnel Information

One of the main complaints about offshore wind industries is the severely higher labour costs for offshore operations. In general, offshore workers require higher wages, and work fewer hours than onshore equivalents. Baseline estimates for all personnel needed for installation of the wind farms, beyond the labour costs included in larger vessel rents, are discussed here.

Offshore personnel are assumed to work on shifts lasting 12 hours, with a rest period between each operation lasting another 12 hours. Given cycles of two weeks offshore prior to a two week rest period, the total number of annual working 12-hour shifts, and correspondingly, days, for offshore personnel is set to 182.5 (Dent et al. 2011). Based on assumptions that offshore installation workers are assumed to be paid similar to offshore wind maintenance workers, annual labour baseline costs are set to €^{2013} 67 000, giving day rates of approximately €^{2013} 370. The estimates are based on UK sector offshore wind energy salaries (Earth Wind & Hire 2013), and adjusted according to assumptions that the relation between direct and indirect labour costs are equal to that of Norwegian oil and gas industry, with indirect costs of approximately 40 % of direct costs (Statistics Norway 2010). Low- and high-cases of day rates are assumed at ± 8 %.

Costs related to personnel employed in the Operations and Maintenance cycle will be presented in section 3.4.3.

2.3.2 Vessel Information

When evaluating vessels relevant for life cycle costs and levelised costs of energy, we choose to disregard pre-installation vessels utilised in the development and consenting phases of offshore wind farms, leaving only vessels used directly for installation, operation and decommissioning of the wind farm for discussion. We differentiate between two main categories, installation and service vessels, although vessels designed for multiple purposes and combinations of installation and service activities exist. Installation vessels, such as crane -, cable-laying -, and anchor handling vessels are primarily designed to handle installation and decommissioning activities, but are also used for large maintenance operations. Service vessels are generally smaller than installation vessels, and supply these stages and tasks through cargo and personnel transportation and tugging operations. Additionally, a so-called *Mother vessel*, acting as an offshore base for technicians and service vessels during the Operation and Maintenance phase is presented.

Installation Vessels

This section is intended to present typical vessels participating in installation of an offshore wind farm. Although the vessel types listed in this section are rarely designed solely for wind turbine installation operations, we will mainly focus on such operations in our descriptions.

Crane Vessels

Crane vessels are designed to lift extremely heavy loads such as substructures, complete turbines or offshore substations, using a deck-mounted crane. They may come with either rotating or fixed cranes (so-called *sheerlegs*), and as either barges or self-propelled ships, with semi-submersible or catamaran hulls preferred over monohulls due to increased stability. Due to the capacity and sheer size of the crane, the crane vessels are often limited both in speed and deck storage capacity, requiring assistance for cargo transportation, manoeuvring and propulsion (Bard & Thalemann 2011).

Figure 37: Shows Oleg Strashnov installing monopiles (Gusto MSC 2012)

Day rate estimates for generic crane vessels suitable for undertaking construction operations set for this thesis have been estimated from day rates for adequate real-life crane vessels. Vessels capable of turbine installation operations at both protected and harsh locations are included.

A generic offshore crane vessel is expected to cost in the region of $€^{2013}$ 400 000 - 600 000 a day (Bomann-Larsen 2013; den Hollander 2013; Midtsund & Sixtensson 2013), based on March 2013 day rates for Subsea7's *Oleg Strashnov* (Figure 37), capable of lifting 5 000 *tons* to 102 *m* (Gusto MSC 2012). These day rate estimates are assumed to include crew costs, but not fuel costs. The crane vessel is assumed to consume between 33 *tons* (idle consumption) and 120 *tons* (full steam consumption) of bunker fuel daily, with a mean consumption of 48.7 *tons* per day (Raadahl & Vold 2013).

A generic crane barge of similar capacity for use in calmer waters is expected to cost approximately $€^{2013}$ 40 000 - 50 000 a day (Bomann-Larsen 2013; Midtsund & Sixtensson 2013). Fuel consumption is expected at approximately 8 *tons* per day (Gundersen, P. G. 2013). The generic crane barge assumed for this thesis is expected to have similar specifications as the HLV Uglen (Figure 38) with a lifting capacity of 600 *tons*. Even though Uglen is expected to be slightly under-dimensioned for installation activities defined in this thesis, the day rates of this vessel are expected to be valid also for more suited vessels (Bomann-Larsen 2013).

Figure 38: The self-propelled heavy lift crane vessel HLV Uglen (Ugland Construction AS 2013)

Mobilisation times for crane vessels are assumed to be one month, and assigned costs are set as a lump sum equalling four day rates.

Jack-up Vessels

Jack-up vessels are multi-purpose vessels used to install bottom-fixed wind turbines in shallow waters. The vessels, which may come as either self-propelled ships or barges, contain three or more legs which the vessel lowers onto the seabed to lift itself above the water line, severely reducing wave, tidal and current impact on the vessel. Jack-up vessels may completely mount a turbine on a foundation, and may also because of their often reduced lifting capacity with regards to crane vessels serve feeder vessels during heavy-lift operations. Due to restrictions on leg lengths, they are not suitable for use in deep waters (Bard & Thalemann 2011).

Generic jack-up vessel day rates are estimated to be around €^{2013} 130 000 - 200 000 (Midtsund & Sixtensson 2013), with mean fuel consumption of approximately 48.7 *tons/day* (Raadahl & Vold 2013). Mobilisation times and corresponding costs are assumed equal to those of crane vessels.

Cable-laying Vessels

Cable-laying vessels are designed and optimised for handling and installation of both inter-array and export cables, and consist of on-deck cable storage facilities and adequate, remotely-operated installation equipment (Bard & Thalemann 2011). For this thesis, cable-laying vessels will not be evaluated in order to estimate cable installation costs, as these costs will rather be evaluated as a function of average installation costs per length unit.

Anchor Handling Tug Supply

Anchor Handling Tug Supply vessels (AHTS) are multi-purpose vessels designed to assist in mooring, tugging and transportation of equipment and cargo for offshore operations. For wind turbine installation purposes, viable use is installation of anchors and mooring lines, tugging of larger components and assistance of larger crane vessels in lifting operations.

Figure 39: KL Saltfjord (Valderhaug 2011)

Figure 39 shows 311 *feet* KL Saltfjord, an AHTS delivering the most powerful bollard pull in the world, having a maximum pull capacity of 397 metric *tons*. The vessel is equipped for operations in the North Sea, and is operated by "K" Line Offshore. (Maritimt Magasin 2011)

For AHTS vessels, costs tend to vary depending on vessel power, impacting towing capacities. Day rates as for a large AHTS equipped with lifting equipment and an ROV is estimated at between €^{2013} 60 000 - 80 000, based on March 2013 day rates for an AHTS rated at more than 22 000 *BHP* (Bomann-Larsen 2013). Additionally, the AHTS is expected to consume approximately 32.5 *tons* of bunker fuel daily (Raadahl & Vold 2013). Mobilisation times are set to three weeks, assigned a lump sum equal to three day rates.

Tugboats

Ranging in size from approximately 70 to 150 *feet*, tugboats are small, manoeuvrable and powerful with respect to their size, and are used for propulsion and manoeuvring of larger vessels either by towing or pushing them (Thorndike 2004). When assisting in offshore operations, tug boats have to be able to handle rough seas. A suitable size for wind turbine installation in Northern European waters is expected to be between 80 and 100 *feet* and have a bollard pull capacity in the region of 50 to 60 *tons*, with approximate day rates at approximately €^{2013} 6 000 - 8 000 (Bomann-Larsen 2013). Additionally, approximately 15 *tons* of fuel is expected to be consumed daily (Bourbon Offshore 2012).

Platform Supply Vessels

Platform Supply Vessels (PSVs) are ships purposely designed to support offshore activities in demanding conditions, illustrated in Figure 40. They often include accommodation facilities, and assist offshore operations through transportation of cargo or personnel. Due to their ability to handle rough seas and demanding weather conditions, they may also be used as personnel rescue vessels.

Figure 40: Platform Supply Vessel illustration (Offshore Energy Today 2012)

A main cost driver for PSV vessels is vessel cargo capacity, through deck space and tonnage capacities. Day rates as of March 2013 for PSVs, with deck areas larger than 750 m^2, is indicated at €^{2013} 30 000 - 36 000, including crew costs (Bomann-Larsen 2013; Midtsund & Sixtensson 2013). On average, these vessel types are estimated to use approximately 20 *tons* of bunker fuel per day (Raadahl & Vold 2013). Mobilisation times and costs are set equal to those of AHTS vessels.

Mobile Crane
A mobile crane is expected to be deployed in loading of turbines onto supply vessels. Day rates for mobile cranes with capacities upwards of 350 *tons*, are set at €^{2013} 5 000 - 7 000, including crew and commodities (Ainschough Crane Hire LTD 2011).

Maintenance Vessels

This section is intended to present typical vessels permanently participating in operation of an offshore wind farm.

Specialised Maintenance Vessels
Specialised service vessels based on so-called SWATH (Small-Waterplane-Area Twin Hull) technology is assumed to transport the service personnel to the wind turbines. These vessels resemble traditional catamarans, but instead of two traditional, parallel hulls, their hulls are made of submerged pontoons connected to the above-water mass by thin structures, as shown in Figure 41. This places the majority of the ship displacement as far below the water surface as possible, resulting in small area at the water plane and increased stability. Because of the vessels' ability to lower themselves, Odfjell's SWATH vessels may sail in significant wave heights up to approximately 2.5 *m* and be moored for work in even higher waves (Odfjell 2013).

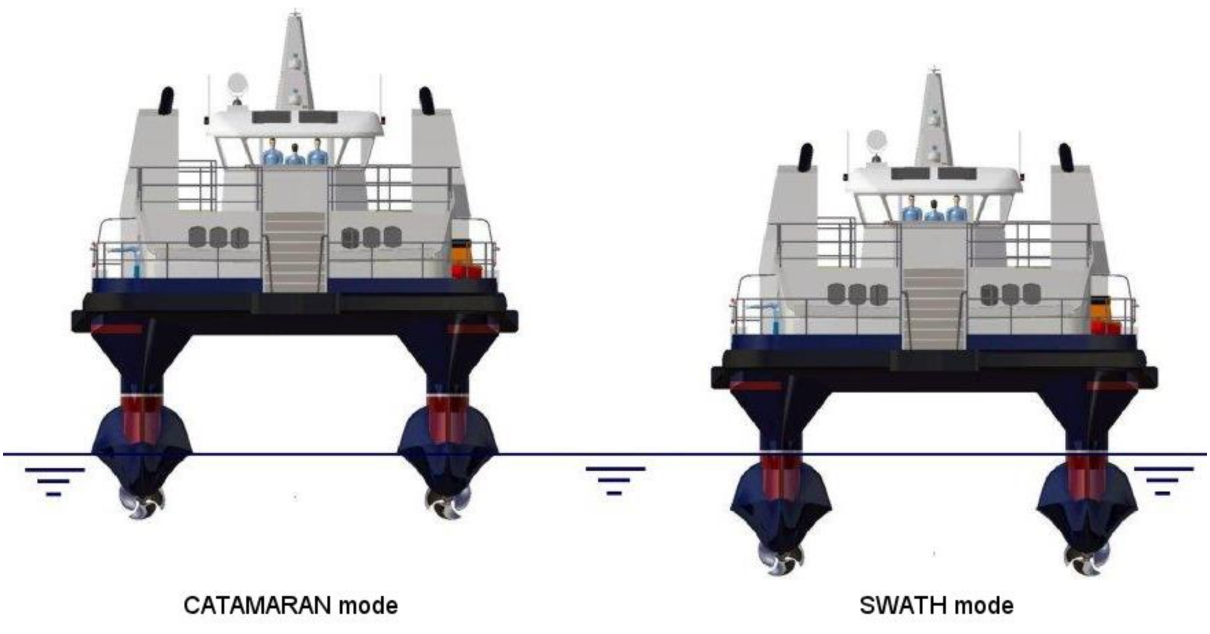


Figure 41: SWATH hull vessel illustration (Odfjell Wind AS 2012)

(Odfjell 2013) estimates the investment cost for the specialised vessel to be approximately €^{2013} 7.5 – 8.5 million. When finding annual costs related to capital costs from vessel investments and vessel operational costs, annuities are based on a discount rate of 6.5 %, accounting for capital costs and risks, and a life time of 20 years. The reason for the somewhat lower discount rate than the previously discussed weighted average cost of capital, is to take into account that acquisition of maintenance vessels may be viewed as a severely less risky investment than a complete wind farm, leading to a lower risk premium on the cost of capital. The annual operational costs which comes from repairs, insurances, crew costs excluding wind farm technicians etc., is stated to be approximately €^{2013} 800 000, and additionally, a daily fuel consumption of approximately 1.5 *tons* is expected (Odfjell 2013). The expected total annual fixed cost for the specialised maintenance vessel is therefore in the range of €^{2013} 1.9 – 2.0 million. (Odfjell 2013)

Mother Vessel

A viable solution for use as a maintenance platform for technicians when offshore distances and weather conditions become so challenging that shuttle transit between port and site seems economically and socially unrealistic, is to use a so-called *mother vessel*. This is a ship capable of accommodating service technicians, smaller maintenance vessels and some spare parts.

Figure 42: Illustration of an offshore mother vessel developed by Ulstein and SeaEnergy (SeaEnergy PLC 2012)

Build costs for a vessel of Ulstein X-bow concept (Figure 42) equipped for operation as a mother vessel in an offshore wind farm has been indicated at €^{2013} 33.9 – 40.7 million. Technical details for the vessel includes a length of approximately 185 *feet*, accommodation for 30 - 45 wind farm maintenance personnel and two to four smaller vessels, small cranes, a gangway system and a crew of approximately 20 persons, including medical, cooking and hygienical personnel. Average daily fuel consumption is assumed to be approximately 6 *tons*. (Moldskred 2013)

Annual operational costs for the mother vessel are estimated at approximately €^{2013} 9.3 million. These costs include crew labour costs, insurances, maintenance, fuel, food etc. Of the indicated €^{2013} 9.3 million, more than 80 % comes from crew costs. (Kjærstad 2013)

Based on an economical lifetime of 20 years and a discount rate of 8.2 %, capital cost annuities are approximately €^{2013} 3.5 – 4.2 million, which leads to annual fixed vessel costs of approximately €^{2013} 12.8 – 13.5 million.

Other Vessels Involved in Maintenance Operations
In addition to the discussed maintenance vessels, real-life operation of an offshore wind farm would require use of other several other vessel types. These vessel types include crane vessels for maintenance or repair operations where heavy components have to be replaced, and these crane vessels could be crane ships for floating concepts and a jack-up vessel for bottom-fixed concepts. Additionally, cable-laying vessels or AHTSs for inter-array or export cable maintenance, supply vessels for component transport, helicopters for special transport etc. are assumed to be used, but these are likely to be chartered on shorter contracts and not evaluated as fixed costs.

Vessel Costs

Day rates for offshore construction vessels depend on several factors, such as the market spot situation from supply/demand mechanisms and contract length.

Seeing as vessel costs account for large parts of the CAPEX and OPEX costs, even small percentage changes in day rates may lead to large changes in actual CAPEX. Table 7 shows the daily baseline installation vessel costs chosen for this thesis.

Table 7: Approximate day rates of different vessels for installation purposes, including mean fuel consumption. All values in €^{2013}

Vessel type	Low	Base	High
Crane vessel	€ 431 000	€ 531 000	€ 631 000
Near-shore crane barge	€ 45 000	€ 55 000	€ 65 000
Jack-up vessel	€ 161 000	€ 196 000	€ 231 000
AHTS	€ 81 000	€ 91 000	€ 101 000
Tug boat	€ 16 000	€ 17 000	€ 18 000
PSV	€ 43 000	€ 46 000	€ 49 000
Mobile crane	€ 5 000	€ 6 000	€ 7 000

Table 8 shows annual fixed costs for vessels permanently employed in operation and maintenance of the wind farms.

Table 8: Annual fixed costs for maintenance vessels, including mean fuel consumption. All values in €^{2013}

Vessel type	Low	Base	High
Specialised maintenance vessel	€ 1 850 000	€ 1 900 000	€ 1 950 000
Mother vessel	€ 12 800 000	€ 13 100 000	€ 13 500 000

In section 5.6, we aim to evaluate how changes in vessel day rates affect total LCOE for the different concepts.

3. LIFE CYCLE COST ANALYSES

In this section, we aim to evaluate total life cycle costs for wind farms of different concepts. The different life cycle phases and cost categories are presented in Figure 43. In chapter 4, the costs will be summarised and discounted to present day values through placing the appropriate cost or percentage distribution of cost at an appropriate point of time.

Figure 43: Life cycle phases for a wind farm project (Mabey Bridge 2013; Navingo BV 2012; RXMD Consulting 2012; Siemens 2012a; Vattenfall 2013)

3.1 Development and Consenting

The purpose of the following section is to evaluate costs related to planning and development of a wind farm, coming from all activities taking place prior to production and acquisition of components necessary for electricity production. This phase may potentially last long, and starts with a political decision to open for energy production in a certain area. Concessions for investigation of site may then be granted to tenders interested in development, installation and operation of the wind farm. Satisfying site conditions with regards to environmental, technical and economical aspects may lead to decisions to request permission to completely develop the farm. Consents and licenses to construct the wind farm and produce electricity have to be granted prior to actual farm construction taking place.

The following section intends to more thoroughly present costs related to the development and consenting phase. This phase, and its related costs, is assumed to be equal for all concepts. Development and consenting is normally divided into two phases; the date up to Final Investment Decision (FID) and the date from FID to Works Completion Date (WCD).

Project development and consenting up to Final Investment Decision (FID) investigates the processes up to the point of either placing firm orders to continue with construction of a wind farm, or closing the project altogether. Many of the key decisions that shape a wind farm project and, accordingly, its total costs, are taken in this phase. Greater investment in wind farm design and optimisation at the development stage will eventually be cost saving later in the project, influenced by both technology and supply changes. This phase consists of wind farm design, environmental impact assessment and survey operations, as shown in Table 9.

Table 9: Overview over cost components included in development and consenting (The Crown Estate 2010)

Components	Function
Project management and development services	Includes feasibility, licensing, planning, radar services and project management.
Environmental surveys	Evaluate environmental impacts by a wind farm on wildlife living in, using or frequenting the surrounding offshore environment, as well as onshore impacts from cables and onshore substations. Consists of benthic (seabed/sedimental), pelagic (open sea species), sea mammal and ornithological surveys. In addition, evaluation of impact on coastline erosion and sedimentation and impact on commercial fishing industries may be assessed through collision risk assessments and commercial fishing studies
Met station surveys	Intended to evaluate meteorological and oceanographic conditions at proposed wind farm site.
Seabed surveys	Analyses of seabed geophysical and geotechnical conditions and characteristics of proposed wind farm site.
Front-end engineering and design (FEED)	Develop the wind farm concept prior to contracting and evaluate areas of technical uncertainty.
Human impact studies	Assessment of impacts on the community living in or around the coastal area near a proposed wind farm. Includes assessment of visual and audible pollution from proposed wind farm, as well as socio-economic and logistical impacts on the infrastructure in nearby coastal area.

Project management and contingencies from FID to WCD includes further investigations and surveys after FID, including FEED studies, environmental monitoring during construction, project management and other administrative and professional services such as accountancy and legal advice and handling of tender offers and enquiries. This includes among others managing engineering studies, construction contract management activities, planning applications and EIA. Project management is an essential part of this phase considering the amount of planning needed for successful construction and operation of a wind farm, and the amount of external contractors participating in these processes. (BVG Associates 2012)

Development and consenting costs are significantly affected by scale of the wind farm. The scope and time spent on the different surveys will depend on several variables, such as the numbers of turbines and the wind farm location. It is likely to see bottlenecks in supply of key services considering the growth of the offshore wind sector, leading to developers looking for acceleration of the development and consenting activities (Renewables Advisory Board 2010).

Table 10: Development and consenting costs for a 500 MW offshore wind farm

Source	**Crown Estate**[1]	**Scottish Enterprise**[2]	**Howard - MS Excel** [3]	**Average**
Development and consenting costs (500 *MW*)	€ 75 807 000	€ 124 774 000	€ 111 736 000	€ 104 106 000

1) Source: (The Crown Estate 2010)
2) Source: (Scottish Enterprise 2011)
3) Source: (Howard 2012)

Table 10 shows development and consenting costs data from studies on a 500 *MW* wind farm with bottom-fixed wind turbines. (The Crown Estate 2010) estimates these costs to contribute around 4.0 % of the total wind farm capital costs, while (Scottish Enterprise 2011) estimates these costs to contribute around 6.5 %.

The costs shown in Table 10 are based on wind farms with bottom-fixed turbines located relatively near shore. One key aspect that will likely be lower for a farm based on floating substructures relative to bottom-fixed farms is the costs related to sea-bed surveys, as the need for data on soil conditions for floating farms only are utilised for anchoring and cable-laying purposes. The reduced sea-bed impact on site, in addition to reduced impact on ornithological aspects, is also expected to reduce costs concerned with environmental surveys. However, costs associated with front-end engineering are assumed to increase, at least prior to maturing and possible standardization of floating wind energy industries. Additionally, meteorological study costs may increase, as deeper waters would require development of floating monitoring stations. Given that few public data on development and consenting costs for wind farms based on floating concepts exist, it is assumed that the costs described in Table 9 are equal for floating and bottom-fixed concept wind farms. This could be considered a conservative estimate.

It is assumed that the development and consenting costs include the entire needed infrastructure employed in the phase, such as administrative offices, port locations etc.

Additionally, all logistical operations associated with construction, installation and decommissioning of the wind farms are assumed to be included in these costs. Costs are expected to include planning layout of wind turbine arrays and optimisation of mooring system layout.

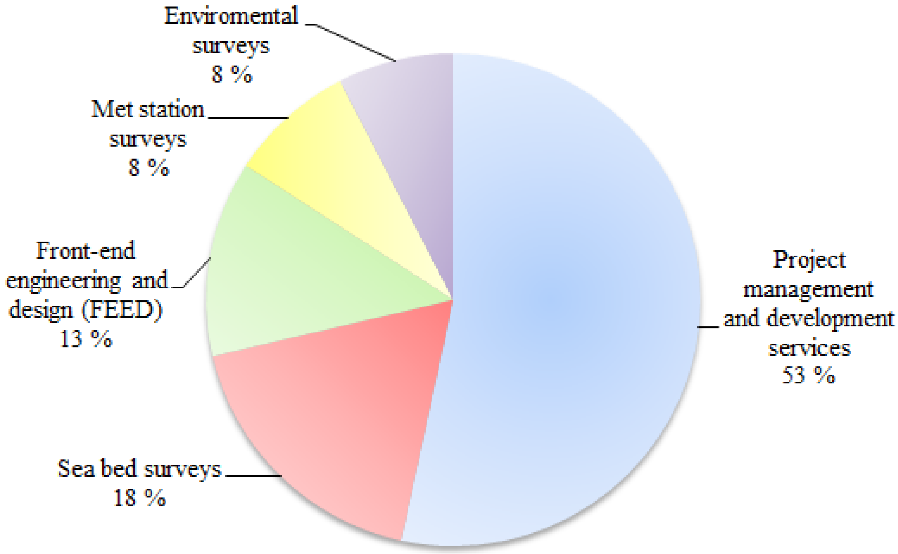


Figure 44: Development and consenting cost breakdown (BVG Associates 2012; Renewables Advisory Board 2010; Scottish Enterprise 2011; The Crown Estate 2010)

Figure 44 shows a breakdown of the development and consenting costs for a 500 *MW* wind farm, averaged from four different sources (BVG Associates 2012; Renewables Advisory Board 2010; Scottish Enterprise 2011; The Crown Estate 2010). Based on the breakdown in Figure 44, the development and consenting costs are expected to be distributed as shown in Table 11. As indicated, project management and development services account for the majority of the development and consenting costs, while combined surveys account for the second largest cost component.

Table 11: Breakdown of the development and consenting costs

Description	**Costs (500 *MW*)**
Project management and development services	€ 55 613 000
Seabed surveys	€ 18 659 000
Front-end engineering and design (FEED)	€ 13 337 000
Met station surveys	€ 8 585 000
Environmental surveys	€ 7 911 000
Total development and consenting costs	**€ 104 106 000**

With these assumptions, the baseline development and consenting costs for the benchmark wind farms are assumed to be approximately €^{2013}104.1 million, corresponding to approximately €^{2013} 208 000 per *MW*. Based on lower and higher data indicated in Table 10, low and high scenarios for per *MW* costs are set to -27 % and +20 %, respectively.

With increasing farm sizes, it is expected that total development and consenting costs will not increase exactly proportional with the farm size increase, but a linear coherence between size and costs is still assumed. Some cost elements, such as costs associated with certain surveys, are assumed to be relatively proportional to farm size, while other, such as FEED costs through mooring system logistical layout and optimising farm with regards to finding a balance between capital expenditures and energy losses may prove to be increasing disproportionally with farm size. For this thesis we have conservatively assumed an increase in total development and consenting cost per 100 additional floating wind turbines within the farm equal to half of the initial development and consenting costs for the benchmark wind farms. Bottom-fixed concepts are expected to have more development and consenting costs proportional to size, as surveys related to benthic conditions at each wind turbine site, as well as individual engineering of the substructures, are necessary. Accordingly, 100 additional wind turbines are expected to induce an additional development and consenting cost of three quarters of the benchmark costs. Cost developments are shown in Figure 45.

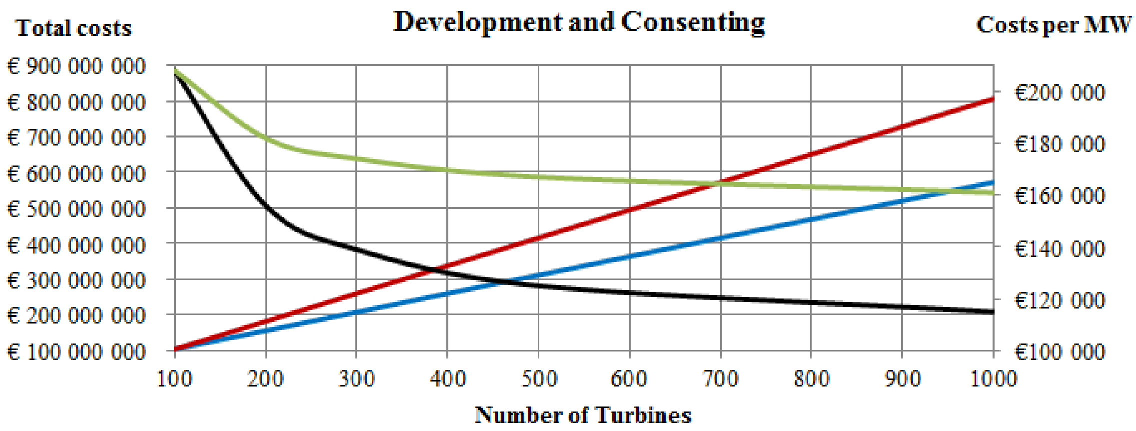


Figure 45: Total development and consenting costs (blue - floating, red - bottom-fixed) and costs per MW (black - floating, green - bottom-fixed), depending on farm size

Construction Phase Insurance

Offshore wind farm projects are capital intensive and involve many contractors and interfaces and careful evaluation of construction risks is important for a successful project. Relatively little experience in construction of offshore wind farms and the complexity of the projects has resulted in several project cost overruns, making insurance essential. The construction phase insurance provides financial protection from physical damage and delays during the assembly, transport and construction stages of a project. It plays an important role in supporting investment in offshore wind projects and is desirable from the perspective of all potential investors. This will move the risks that can potentially negatively affect the cash flow of the project, which is the key area of concern for investors at this stage. (PricewaterhouseCoopers 2012)

The insurance market for offshore wind is still relatively immature, and there are limited public data on the construction stage risks for offshore wind available today (PricewaterhouseCoopers 2012). Table 12 shows a typical insurance package covering the entire construction period.

Table 12: Construction phase insurance (PricewaterhouseCoopers 2012)

Product	Triggering events	Scope	Status for offshore wind
Construction All Risk (CAR)/ Erection All Risks (EAR)	Physical loss of and/or physical damage to the “Works” (CAPEX) during the construction phase of a project.	All risks of physical loss or damage including all contact parties as named Insurers through a single insurance interface which includes contractor and subcontractors.	Compared to the more established onshore wind sector, there are sometimes restrictions on the level of cover available, in particular, cover for defects and the consequences of defects and serial failures, reflecting the more complex construction process. This results in higher premiums and deductibles.
Delay in start-up (DSU)/Advance Loss of Profits (ALOP)	Physical loss of and/or physical damage during the construction phase of a project causing a delay to project handover.	Loss of revenue as a result of the delay triggered by perils insured under the CAR policy.	
Third party liability	Physical loss or damage to people and/or property.	All risks of physical loss or damage to a third party.	

A typical construction phase insurance package covering physical damage and delay in start-up shown in Table 12 is expected to have a constant cost of around €^{2013} 50 000 per *MW*, adding up to €^{2013} 25 million for a 500 *MW* offshore wind farm (PricewaterhouseCoopers 2012). Low and high case scenarios are set to ± 10 %.

Contingency

As offshore wind farm projects are capital-intensive and involve many contractors and interfaces, careful evaluation of construction risks is very important. Potential negative events not covered by insurances may occur during the lifetime of the wind farm, and a contingency could be applied to cover uncertainties related to all procurement and installation related cost. The contingency is defined as a percentage addition to the CAPEX costs (excluding development costs up to FID, construction phase insurance and other financing fees), and a commonly used share is 10 % (Multiconsult 2012). The contingency could negatively affect discussions on whether to complete a future, capital-intensive project, but could conversely be of great importance for minimising the difference between budgeted and obtained life cycle results in an immature market as floating, offshore wind industry is.

Naturally, it would be preferable to foresee costs related to all future risks to reduce contingencies, but at the same time, it is important to realise that potential negative events are not likely to be expected, and that to be financially able to reduce impacts of negative uncertainties is a key aspect in operating a viable wind farm over the course of several years.

Adding a contingency value to baseline CAPEX costs when developing grounds for an investment decision may be key to stay within budget. For this thesis, it is however decided that these contingencies are covered when evaluating low-case scenarios for CAPEX costs, and accordingly, contingencies are left out of baseline evaluations. In section 5.6, effects on levelised costs of energy for the evaluated concepts by adding varying contingency percentages will be introduced.

3.2 Production and Acquisition

This section aims to present all capital expenditures coming from production and acquisition of all components that combined form the wind farm. These components include substructures, turbines, mooring systems and all electrical equipment necessary to connect the wind farm to the onshore grid. However, this section does not embrace capital expenditures coming from installation of said components, as these costs are presented in section 3.3.

3.2.1 Turbine Costs

As explained in section 2.2.2, all concepts, whether on- or offshore, are assumed to be deployed using generic turbines based on the theoretical NREL 5 *MW* turbine. One exception is SWAY, where the tower is an integrated part of the floater, thus removing the need for a tower to be provided by a turbine manufacturer, resulting in turbine costs for this concept being reduced by an adequate percentage to account for the tower costs.

Depending on floater configuration, tower height is varied so the top of the tower is set at 87.6 MAMSL, resulting in a hub height of 90 *m*.

Based on data from the Crown Estate, a cost breakdown of a generic offshore turbine is presented in Figure 46 (The Crown Estate 2010).

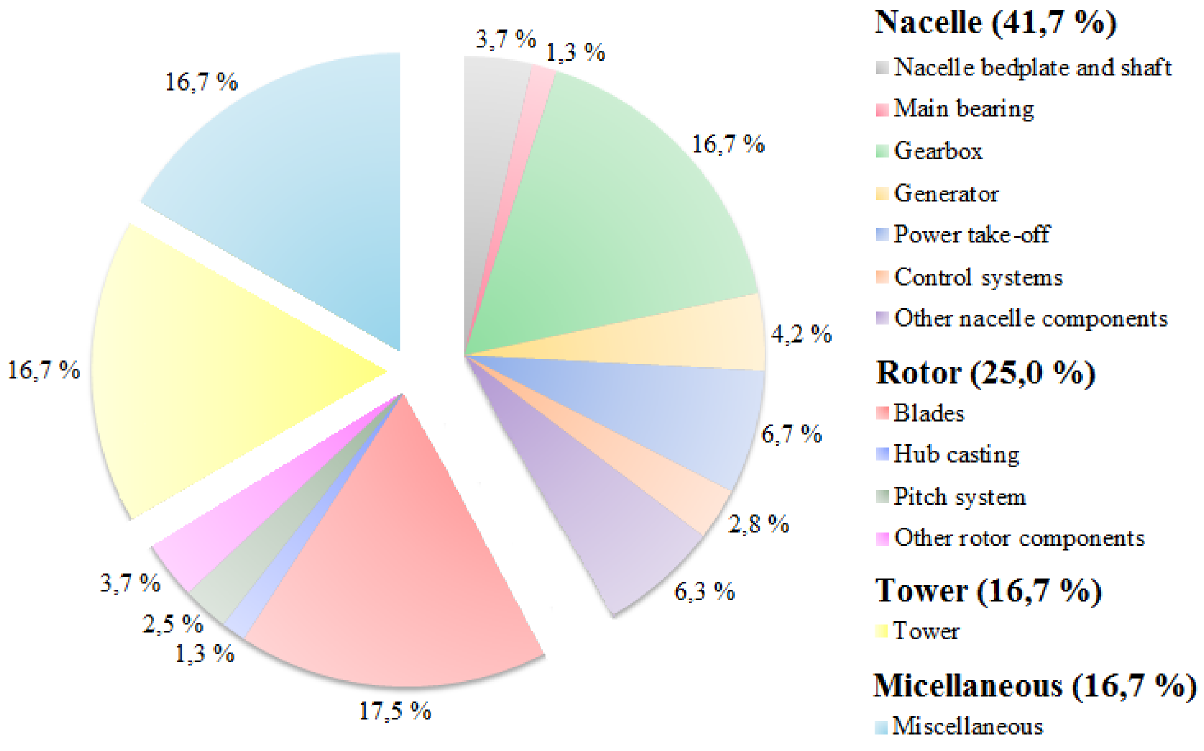


Figure 46: Cost breakdown for an offshore turbine. From 12 o'clock, counting clockwise: Nacelle, rotor, tower and miscellaneous costs (The Crown Estate 2010)

As indicated, the nacelle and its containing electronic equipment accounts for the single largest part of the turbine cost. Although being severely lighter than both the tower and the nacelle, with significantly less steel consumption, the rotor accounts for nearly a quarter of total turbine costs. This is likely to be due to the consumption of expensive glass and carbon fibre and the moulding production technique (Figure 47).

Table 13: Generic 5 MW offshore turbine costs

	The Crown Estate[1]	RCN[2]	Scottish Enterprise[3]	NVE[4]	The Crown Estate[5]	Average
Nacelle	€ 3 159 000	€ 2 821 000	€ 3 178 000	NA	NA	-
Rotor	€ 1 895 000	€ 2 015 000	€ 2 241 000	NA	NA	-
Tower	€ 1 263 000	€ 2 015 000	€ 1 598 000	NA	NA	-
Miscellaneous	€ 1 263 000	€ 1 209 000	€ 514 000	NA	NA	-
Turbine	**€ 7 580 000**	**€ 8 060 000**	**€ 7 531 000**	**€ 6 956 000**	**€ 7 249 000[6]**	**€ 7 475 000**
Turbine (excl. tower)	**€ 6 317 000**	**€ 6 851 000**	**€ 7 017 000**	**€ 5 797 000[6]**	**€ 6 041 000**	**€ 6 405 000**

1) Source: (The Crown Estate 2010)
2) Source: (Douglas Westwood 2010) on behalf of The Research Committee of Norway
3) Source: (Scottish Enterprise / Douglas Westwood 2011). (Converted from £^{2011})
4) Source: (Multiconsult 2012) on behalf of The Norwegian Water Resources and Energy Directorate
5) Source: (Howard 2012) - MS Excel LCOE model
6) Interpolated from a tower cost percentage of 16.7 % of total turbine costs as suggested in Figure 46

Table 13 shows turbine cost data from studies conducted on behalf of The Crown Estate, The Research Committee of Norway (RCN), The Scottish Enterprise and The Norwegian Water Resources and Energy Directorate (NVE), which suggests an average cost of generic 5 *MW* offshore turbines to be approximately €^{2013} 7.5 million, and an average RNA cost to be approximately €^{2013} 6.4 million (± approximately 10 %). To account for different tower/floater configurations, tower costs for different concepts will be presented as a part of concept production cost evaluations. SWAY is designed to accommodate down-wind turbines, and given large-scale production, we assume equal turbine costs for up-wind and down-wind turbines, corresponding with opinions of thesis advisor Anders Myhr (Myhr 2013).

Turbine costs are assumed to be constant with increasing farm sizes.

Figure 47: Rotor blade production (Pagnamenta 2010)

3.2.2 Substructure and Tower Costs

The total production costs for the substructures, both floating and bottom-fixed, rely both on the material consumption and on the manufacturing costs of the substructures. Total production costs for towers are presented prior to bottom-fixed and floating substructures to illuminate approximate distribution between said costs. The costs presented in this section are assumed to be proportional with increasing production volume.

Tower Material Consumption and Production Costs

Based on the generic turbine costs presented in section 3.2.1, a generic turbine tower is expected on average to cost €^{2013} 1.1 million. The unmodified NREL 5 *MW* turbine has a tower weight of approximately 350 *tons* of steel (Butterfield et al. 2009), and with a given bulk steel price of €^{2013} 1 000 per *ton*, this corresponds to an average tower bulk material cost which equals roughly one third of the total tower cost. These estimates correspond well with indications from (de Vries 2011), stating that conical structures such as wind turbine towers are produced in quantities for costs in the region of €^{2013} 2 000 - 3 000 per *ton*. Conservative calculations based on these indications suggest a total tower cost of €^{2013} 1.1 million, showing a concordance between generic turbine prices and estimates based on total weight, resulting in use of these estimates for our thesis.

Based on data presented in Table 5, the modified NREL 5 *MW* tower is expected to contain approximately 233 *tons* of steel. Assuming a baseline steel price of €^{2013} 1 000 per *ton*, the baseline tower material costs are expected at approximately €^{2013} 233 000, while the total production costs are rounded to €^{2013} 700 000. These figures are used for all but two concepts discussed in the thesis. One exception is SWAY, where the tower is an integrated part of the tower design. The other exception is TLB X3, which has a floater configuration ending at 15 *m* above MSL, resulting in a tower 5 *m* shorter than the remaining concepts. A simplified linear distribution between height and total cost is assumed, leading to tower cost reductions just shy of 6.5 %, giving a baseline tower cost for the TLB X3 concept of €^{2013} 658 000. These numbers are also assumed used for the bottom-fixed reference concepts, with substructures assumed to end at 15 MAMSL.

The differences between these tower costs and those presented in Table 13 come from the assumptions that towers are modified to reach a hub height of 90 *m*. Low and high case scenarios for tower costs are set to ±20 %.

Bottom-fixed Substructures

Production costs through material and manufacturing costs for bottom-fixed substructures are estimated prior to production costs for floating concepts to act as reference values.

Substructure Material Consumption

Dimensions of bottom-fixed substructures do not only rely on water depth and turbine dimensions, but also on highly site-specific data such as seabed and weather conditions. Even within one single park, substructures placed in equal water depths may vary severely in weight from differences in both diameter and penetration depth due to benthic differences.

Based on estimated and actual[2] monopile weights for water depths between 25 and 37 *m*, an average monopile weight of approximately 870 *tons*, of which 630 *tons* for the actual pile and 240 *tons* for the transition piece, is suggested for a water depth of 30 *m* (de Vries 2011; Lindø Offshore Renewables Center 2013). However, as 5 *MW* turbines have only emerged in the later years, these values come from weights for monopiles supporting 3.6 *MW* turbines. To account for this, one solution could be to evaluate monopile constructions using turbines of lower capacity. However, it is assumed changing downscaling of the turbine ratings would have severe ripple effects for the further analysis, e.g. through energy production and costs related to grid connection. Additionally, scaling of turbines contradicts assumptions set on comparing concepts at terms as equal as possible. Nevertheless, benthic conditions seem to have greater impact on monopile dimensions than actual turbine rating, leading to conservative assumptions that total weight for the monopiles in this thesis could be adjusted only according to the expected thrust force difference between the two turbine sizes, assumed to be linear to the turbine rating difference (Lindø Offshore Renewables Center 2013; Myhr 2013). Accordingly, total monopile weight for use at 30 *m* water depths is estimated at approximately 1 200 *tons*.

5 *MW* jacket structures for deployment at 30 *m* are estimated to weigh approximately 825 *tons*, distributed between 510 *tons* of jacket weight (primary and secondary constructions) and 315 *tons* of mooring piles (Seidel 2007).

Manufacturing Process for Bottom-fixed Substructures

The manufacturing process (Figure 48 and Figure 49) for the different support structures starts with creating the primary elements, for both the foundation structure and for the transition piece. Sheets of steel produced in the required dimensions are delivered from a steel producer for further processing. The sheets are rolled into tubular sections and the edges are prepared for welding. The tubular section is welded both from outside and inside at the seam. To reduce any stress concentrations, the welds are ground if necessary. The welding processes of such tubular sections are often done in automated processes and the quality of the weld is ascertained by non-destructive testing. Eccentricities and general shapes of the tubular sections are inspected to be within allowed tolerances. (de Vries 2011)

Figure 48: Parts of manufacturing processes for monopile structures (de Vries 2011)

The further manufacturing process is substantially different for monopile structures than for jacket structures. Monopile structures consist of large diameter sections that are heavy, and the sections are relatively easy lifted into alignment and welded together on top of each other.

[2] BelWind, DanTysk, Greater Gabbard, London Array and Meerwind

Figure 49: Parts of manufacturing processes for jacket structures (de Vries 2011)

Relative to monopiles, jacket structures consist of much smaller sections that must be prepared by cutting the brace stubs into the exact predefined shape allowing a perfect fit at a predefined angle. The joints are then lifted into alignment and welded together with the main legs of the jacket, and the assembly of the structure involves welding of many connections. Large-scale production of substructures in specialised production facilities offers opportunities for automation of the production processes, but given the added geometry complexity for jackets relative to monopiles, automation of production processes are expected to be performed to a severely lesser extent for jackets than for monopiles.

After the primary structure is assembled, it requires blasting and the application of a protective coating. Subsequent items such as ladders and platforms are then mounted.

Manufacturing cost assumptions for bottom-fixed substructures are based on an addition of 100 % and 400 % on baseline material costs for monopiles and jacket structures, respectively, to accommodate assumptions that monopile material costs account for approximately 50 % of total production costs (Faaij & Junginger 2004), expected at approximately €^{2013} 2 000 per *ton* (de Vries 2011), while total production costs for jackets are expected at €^{2013} 4 000 - 6 000 per *ton* (Borgen 2010; de Vries 2011). These estimates are supported by Rambøll Offshore Wind (Offshore Center Danmark 2012). Based on these figures, material costs, manufacturing costs and corresponding total production costs estimates are presented in Table 14, given an expected baseline steel cost of €^{2013} 1 000 per *ton*.

Table 14: Production cost estimates for bottom-fixed substructures

Concept	Monopile	Jacket structure	
		Jacket	Piles
Material consumption (*tons*)	1 200	510	315
Material costs	€ 1 200 000	€ 510 000	€ 315 000
Addition	100 %	400 %	100 %
Manufacturing costs	€ 1 200 000	€ 2 040 000	€ 315 000
Total production costs	**€ 2 400 000**	**€ 3 180 000**	

As indicated in the table, total production costs of monopiles are roughly three quarters of production costs for jacket structures. Even though material costs are lower for jackets than monopiles, the complex geometry complicates manufacturing processes, leading to substantially higher production costs. From a substructure production point of view, choice of monopiles over jackets generally looks favourable if the wind farm site conditions qualify for the use of monopiles. However, jacket structures are expected to be more competitive in deeper waters and under harsher weather conditions.

Floating Substructures

As of spring 2013, only two megawatt scale floating pilot wind turbines, the Hywind pilot and the WindFloat pilot, have been deployed, leading to lack of data on production costs for large-scale production of floating substructures.

The Hywind pilot floater was built in Finland by Technip over a period lasting more than half a year (Technip 2010). It seems obvious that if floating wind projects were to be realised, large-scale production of substructures would lead to unit costs and production times severely lower than one-of productions of pilots and prototypes. As to the question of who possible producers might be, it seems natural to consider producers of bottom-fixed substructures as companies who might expand their operations to include production of floating substructures. Production of both floating and bottom-fixed substructures likely include many similar operations with regards to handling and manipulating large steel volumes into structures of large diameters. Other possible actors include shipyards, larger multidisciplinary energy companies (Technip, Aker, Siemens etc.) and possibly specialised wind turbine producers due to their capabilities for producing tubular steel sections.

Floating structures may be produced at a number of facilities, with indoor factories or dry docks as two feasible solutions. The latter solution may require larger capital investments, but flooding of the dock after production could simplify launching and towing operations.

Substructure Material Consumption

So far, offshore wind turbine substructures consist mainly of welded and processed steel. We will focus on steel consumption contributing to the dry weight of the substructures.

Substructure steel consumptions and material costs for the different concepts are presented in Table 15, based on baseline steel costs.

Substructure Manufacturing

The manufacturing process for wind turbines consists of all tasks exercised to alter and modify bulk steel and other materials to complete wind turbine components. Examples of such tasks include rolling, cutting, painting and corrosion treatment of steel plates, and welding and miscellaneous assembly of materials into complete structures.

It seems obvious that large-scale production of large, offshore structures in a maturing market, taking specialised production facilities, automated processes and other economies of scale into account, could severely diminish human labour dependency and unit production times.

An approximate approach to estimating substructure manufacturing costs could be to adequately divide the total production costs between material and manufacturing costs. Statoil suggests a rule of thumb where large-scale production and automated processes could make labour costs be assumed to approximately equal to material costs, corresponding to ratios for bottom-fixed structures (Byklum 2013; de Vries 2011; Faaij & Junginger 2004). It is important to point out that the material costs in question do not only come from bulk materials, but also from course modifications and treatments of materials, and that the rule of thumb could only be assumed valid for relatively simple or non-complex structures of modest sizes. Structural complexity will increase labour intensity, while structural size could affect labour costs both positively and negatively from automation possibilities and handling problems, respectively. Relatively simple offshore wind turbine floaters such as Hywind could in this perspective be viewed as modestly simple structures, making the rule of thumb applicable for the less complex floater concepts (Byklum 2013; Myhr 2013).

For this thesis, it is decided that manufacturing costs are estimated as a percentage addition to baseline material costs, adjusted for expected structural complexity of concept. Addition percentages are based on correspondence with advisor Anders Myhr on geometries, diameter transitions, stiffeners etc., and these addition values are shown in Table 15 and further presented in Appendix 5.

Total Concept Production Costs

Total production costs for each concept, given large-scale production in a mature industry, are given as the sum of the material and manufacturing costs and presented in Table 15.

Table 15: Production cost estimates for floating substructures

Concept	**TLB B**	**TLB X3**	**Hywind II**	**WindFloat**	**SWAY**
Material consumption (costs)	445[1]	521[1]	1 700[2]	2 500[3]	1 100[4]
Material costs	€ 445 000	€ 521 000	€ 1 700 000	€ 2 500 000	€ 1 100 000
Manufacturing costs addition	110 %[5]	130%[5]	120 %[2.5]	200 %[5.6]	150 %[6]
Manufacturing costs	€ 489 500	€ 677 300	€ 2 040 000	€ 5 000 000	€ 1 650 000
Total production costs	**€ 934 500**	**€ 1 198 300**	**€ 3 740 000**	**€ 7 500 000**	**€ 2 750 000**

1) Source: (Myhr & Nygaard 2012)
2) Source: (Byklum 2013)
3) Source: (Weinstein 2009)
4) Source: (Jorde 2013)
5) Source: (Myhr 2013)
6) Source: (Borgen 2010)

As suggested in the table, WindFloat seems to be the most expensive solution when evaluating production costs for floating substructures, coming from large steel consumption and complex geometry. Conversely, TLB B seems like the least expensive substructure to produce, from low steel consumption and relatively non-complex geometry. By comparison with Table 14, it seems only the TLB concepts are competitive to monopile substructures when looking at production costs. Additionally, the tower consumption for SWAY is included in the production costs, indicating that SWAY is also competitive to monopiles when disregarding tower costs. However, possible counteracting of these costs through mooring system costs are presented later in the chapter.

Lower and higher values for production costs, both for bottom-fixed and floating concepts, are conservatively set to ± 40 %, to account for steel price volatility.

3.2.3 Mooring System

A mooring system is used to confine a ship or floating structure to a specific location. In this thesis, the mooring systems of the evaluated wind turbine concepts are divided into three main categories; catenary mooring systems, vertical mooring systems and taut leg mooring systems (Figure 50).

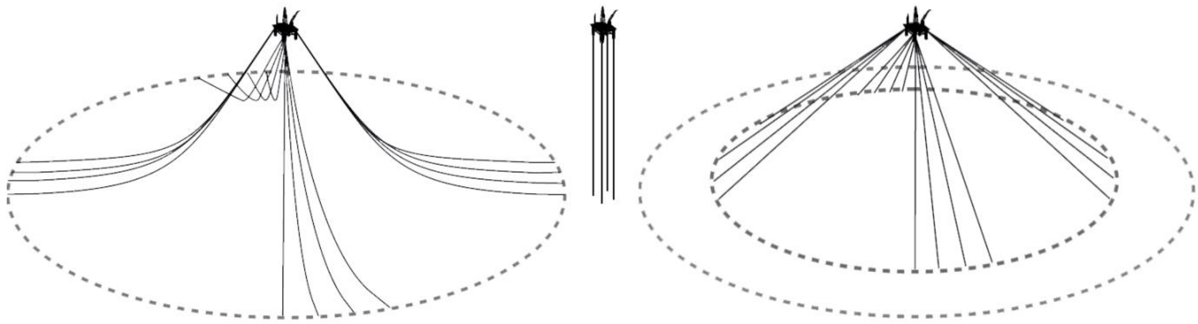


Figure 50: Catenary system, vertical system and taut leg system, derived from (Vryhof Anchors BV 2010a)

The major difference between these systems is that catenary mooring lines arrive the seabed horizontally, vertical mooring lines arrive the seabed vertically and taut leg mooring lines arrive the seabed at an angle. Taut leg mooring system is therefore capable of resisting both horizontal and vertical forces, and restoring forces are generated by elasticity of the mooring lines. The vertical mooring system is also capable of withstanding both horizontal and vertical loads, although horizontal loads are not withstood to the same extent. For catenary mooring, the anchor point is only subjected to horizontal forces, and most of the restoring forces are generated by the weight of the mooring line. For catenary mooring systems a large mass clump weight or a buoyancy element may be attached to the mooring lines, creating vertical forces to influence system stiffness. A disadvantage for the catenary mooring is that the footprint is bigger than the mooring radius for the other systems with a similar application, affecting total wind farm seabed area (Vryhof Anchors BV 2010a).

A mooring system consists of a mooring line, connectors and an anchor. A mooring line connects the anchor on the seafloor to a floating structure, and is typically divided into chain, wire rope or synthetic fibre rope. Anchors are typically divided into a dead weight anchor, drag embedment anchor, pile anchor, suction anchor or vertical load anchor, as illustrated in Figure 51 (Vryhof Anchors BV 2010a).

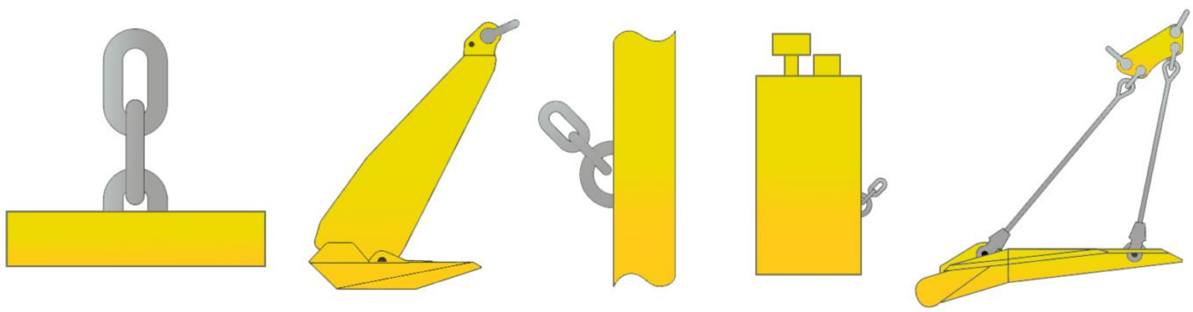


Figure 51: Different types of anchors. From left to right: Dead Weight Anchor, Drag Embedment Anchor, Pile Anchor, Suction Anchor or Vertical Load Anchor (Vryhof Anchors BV 2010a)

Anchors for Different Mooring Systems and Floater Concepts

For this thesis, an exact site location is not decided, and seabed soil conditions are therefore assumed to be homogenous, medium clay for purposes of simplifying the thesis. In real life, soil conditions at a feasible farm site could be expected to vary in type and density, leading to required use of various anchor types, possibly of different costs and installation procedures.

Anchor for Catenary Mooring System

In a catenary mooring system the anchor line arrives at the seabed horizontally and a Drag Embedment Anchor (DEA) (Figure 52) is traditionally preferred. This type of anchor is the most popular type of anchoring point available today. The anchor has been design to penetrate into the seabed, either partly or fully. The resistance of the soil in front of the anchor generates the holding capacity and is therefore capable of withstanding large horizontal loads (Ice Engineering 2009).

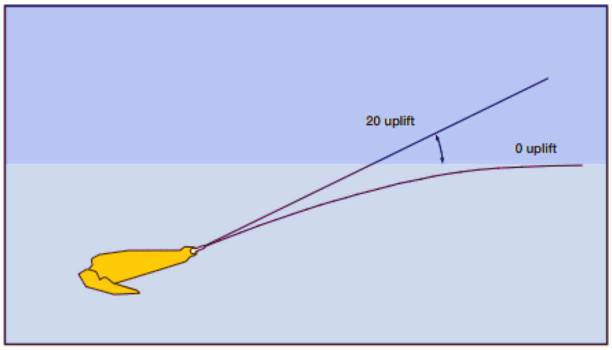


Figure 52: Illustration of Drag Embedment Anchor (Vryhof Anchors BV 2010c)

In order to cope with the forces involved in catenary mooring operations, it is expected that each designated anchor must be able to withstand a horizontal force of 500 *tons* (Myhr 2013). A 17 *ton* Stevshark Mk5 (Figure 53) designed by Vryhof Anchors BV meets the calculated requirements and is chosen for mooring of concepts requiring catenary mooring in this thesis because the anchor is well proven and readily available, with a unit price of approximately €^{2013} 114 000 (Vryhof Anchors BV 2013), with low and high case scenarios set to ± 25 %. These anchors could be employed for a variety of soil conditions, as the anchors may be optimised for varying soil conditions by adjusting the shank angle relative to the fluke.

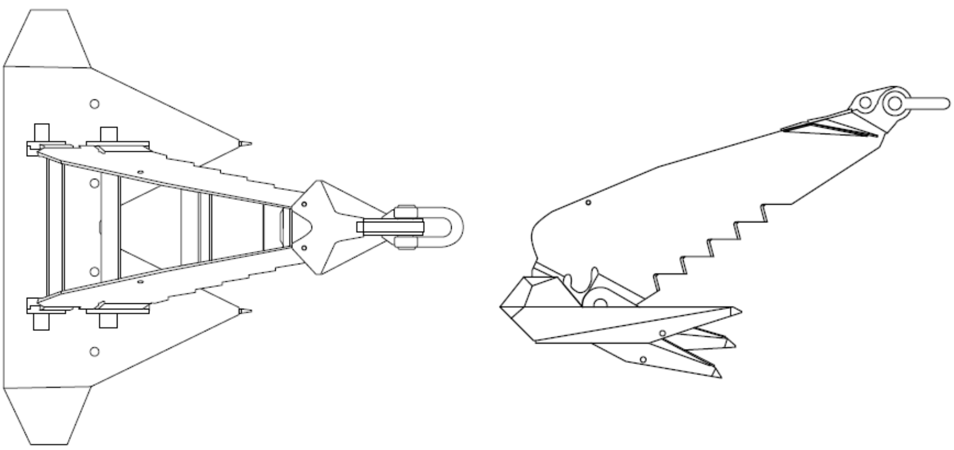


Figure 53: Top and side view of the Stevshark anchor (Vryhof Anchors BV 2010a)

Anchor for Vertical Mooring System

In a vertical mooring system the mooring line arrives at the seabed vertically. One possible anchor type could be a Suction Pile Anchor (SPA), a large diameter hollow steel pipe (Figure 54), installed by being sucked into the seabed by a removable pump. The friction of the soil along the pipe and lateral soil resistance generates the holding capacity, and the anchor is therefore capable of withstanding both horizontal and vertical loads (Ice Engineering 2009).

The estimated excess buoyancy of the SWAY concept, which relies on vertical mooring, is expected to be approximately 700 *tons* (Jorde 2013). SPAs capable of withstanding vertical such loads in medium density clay soils are expected to have total weights of approximately 140 *tons* (Jorde 2013). Total production costs for SPAs are expected to be in the region of approximately €^{2013} 9 500 - 11 000 per *ton* of anchor, and given large-scale production, cost estimates for each unit of suction pile anchor capable of withstanding 700 *tons* of vertical force are set to approximately €^{2013} 1.3 – 1.5 million (Ekrem 2013).

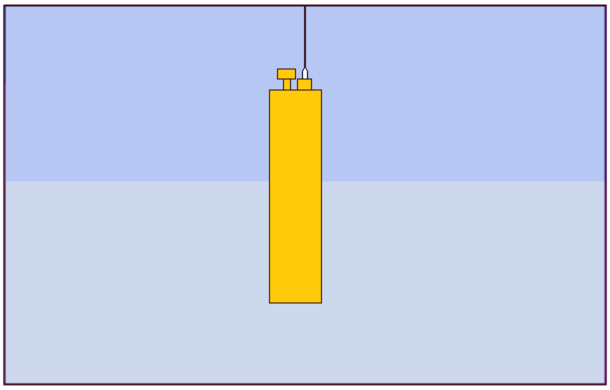


Figure 54: Illustration of a Suction Pile Anchor

Anchor for Taut Leg Mooring System

In a taut leg mooring system the anchor line arrives at an angle of approximately 45˚ at the seabed and use of an anchor capable of withstanding vertical loads, such as a Vertical Load Anchor (Figure 55) is necessary. The anchors need to be designed to withstand a maximum mooring design load of approximately 2 000 *tons* at 45° angle, of which approximately 900 *tons* comes from the resultant force from the concept excess buoyancy, while the rest comes from load amplitudes (Myhr & Nygaard 2012; Myhr 2013).

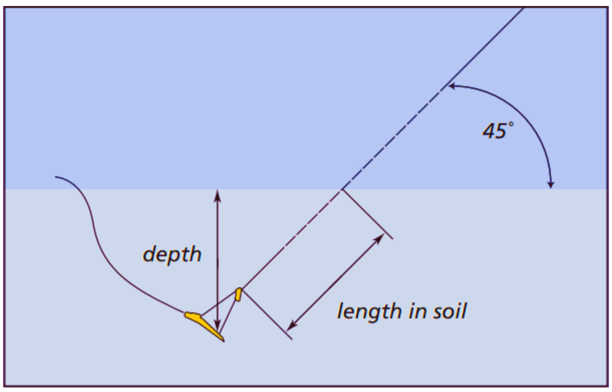


Figure 55: Illustration of Vertical Load Anchor (Vryhof Anchors BV 2010b)

The Stevmanta VLA (Figure 56) designed by Vryhof Anchors BV meets the calculated requirements and is chosen for this type of system because it is the smallest and lightest deep water anchor available on the market. The suitable fluke size of the Stevmanta VLA anchor is 28 m^2, corresponding to a 40 *ton* anchor with a budgetary price of approximately $€^{2013}$ 278 000, significantly less than an SPA of equal capacity (Vryhof Anchors BV 2013). Low and high case scenarios for VLA prices are set to ± 25 %.

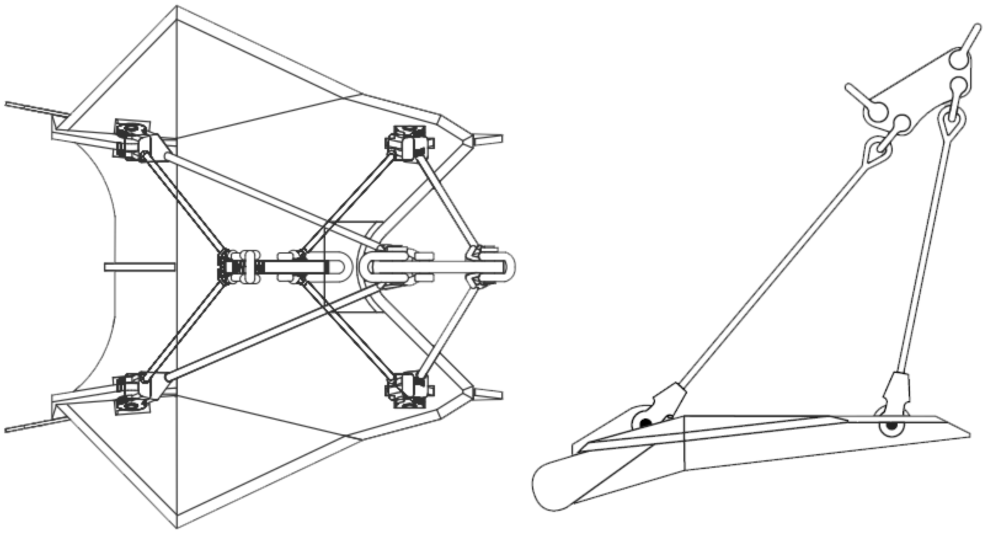


Figure 56: Top and side view of the Stevmanta Vertical Load Anchor (Vryhof Anchors BV 2010b)

Taut leg mooring systems could also be installed using suction anchors. However, as indicated in the previous section, suction anchors are expected to be significantly more expensive than VLA anchors. These cost differences are not expected to be neutralised by installation processes, both due to the sheer size of suction anchors and the fact that they are installed through time-consuming pumping operations.

Anchor type summary

Table 16 summarises key advantages and disadvantages related to the different anchor categories.

Table 16: Advantages and disadvantages for offshore anchor types (Eriksson & Kullander 2013)

Anchor Type	Advantages	Disadvantages
Drag Embedment Anchor (DEA)	- Proven technology. - Suited to resist horizontal loads. - Easily retrievable.	- Exact anchor position cannot be guaranteed. - Can only take minor vertical loads.
Suction Pile Anchor (SPA)	- Exact position of anchor location. - High holding power in most soil conditions. - Suited to resist both horizontal and vertical loads.	- More costly installation. - May require a larger anchoring vessel and more equipment. - Large and bulky to handle.
Vertical Load Anchor (VLA)	- Proven technology. - Suited to resist both horizontal and vertical loads.	- Exact anchor position cannot be guaranteed.

Mooring Lines

A mooring line is used to connect an anchor to a floating structure, and is typically divided into chain, wire rope, synthetic fibre rope, or a combination of these. Fibre ropes are often made of polyester or polyethylene, while chain and wire ropes are made of steel. Choice of mooring line depends on a number of technical parameters such as the type of mooring system, water depth, seabed characteristics, and excited loads and required motion characteristics of the floating structure. During the lifetime of the wind farm, the mooring force continuously varies in the mooring system, as well as the angle of the line to the seabed. As a result, the mooring lines are subjected to mechanical wear and tear, which favours use of chain near the seabed since these are more resistant to sea floor wearing than ropes. Additionally, clump weights may optionally be hanged onto the mooring lines to optimise the stiffness of the mooring system. However, consumption of clump weights and their respective costs are assumed to be so uncertain they will not be evaluated further.

Table 17 summarises key advantages and disadvantages related to the different mooring line types. (Eriksson & Kullander 2013)

Table 17: Advantages and disadvantages for offshore mooring line types (Eriksson & Kullander 2013)

Mooring Line Type	Advantages	Disadvantages
Steel Wire Rope	- Easy to install - Limited weight	- Reduced resistance against wear and tear from long term contact with the seabed - Prone to material fatigue
Steel Chain	- Can withstand long term contact with the seabed	- Heavy weight negatively affecting installation - Will not penetrate deep into the soil
Synthetic Fibre Rope, polyester or polyethylene	- Easy to install - Low weight	- No resistance against wear and tear from long term contact with the seabed, without use of coating - Detoriation of structural performance over time

Mooring Line Costs

Here, key costs for certain mooring line types and dimensions are presented. Costs are estimated to include economies of scale with regards to purchasing prices, and the mooring line consumption for the benchmark wind farms are expected to be so vast no additional economies of scale are assumed for increases in farm size. Low and high case scenarios for mooring line costs are set to ± 25 % of baseline costs, with one exception for vertical mooring systems, presented accordingly.

Synthetic fibre ropes made from woven synthetic fibres are assumed to be used for taut leg mooring systems for the TLB concepts. The fibre ropes are expected to be required to withstand a pre-tension force from excess buoyancy equal to approximately 1 000 *tons*, and load amplitudes of approximately 800 *tons*, leading to a total capacity of approximately 1 800 *tons* (Myhr & Nygaard 2012; Myhr 2013). For taut leg mooring systems, stiffness is required to exceed minimum stiffness requirements, regardless of depths, and for the TLB systems, these stiffness requirements are expected to be approximately $8 \cdot 10^6\ {}^{N}/_{m}$ and $5.6 \cdot 10^6\ {}^{N}/_{m}$ for the upper and lower mooring lines, respectively (Myhr 2013). Cost indications from (Shahid 2013) suggest approximate benchmark farm upper and lower mooring line costs to approximately €^{2013} 617 and €^{2013} 602 per *m*, respectively. Cost estimations for fibre rope mooring lines are further presented in Appendix 6.

It is decided to delimitate the thesis towards uncertainties on whether or not present fibre rope technology is suited for deployment at water depths below 500 *m*. Industry experts indicate uncertainties with regards to creep and fatigue effects associated with use of fibre ropes on such depths, and these uncertainties are expected to be best addressed through expensive full scale tests (Ekrem 2013; Henanger 2011).

Figure 57: Cross sectional area of generic fibre rope (Bridon 2011)

A combination of chains and steel wires (Figure 58 and Figure 59) are assumed to be used as mooring lines for catenary mooring system concepts, i.e. Hywind and WindFloat. These mooring systems must be able to withstand horizontal forces of approximately 500 *tons*, and to lower the risks of mooring lines failing prior to the anchor being pulled out of the seabed soil if an extreme load scenario were to occur, breaking loads for wires and chains are set somewhat higher than anchor capacities (Myhr 2013). A suitable chain for these mooring systems could be a 76 *mm* R5 mooring chain, expected to cost approximately €^{2013} 250 per *m* (Fossen Shipping 2013). These chains are expected to weigh roughly 126.5 *kg* per *m*, with proof loads and minimum break loads of approximately 500 *tons* and 715 *tons*, respectively (American Bureau of Shipping 2009). Corresponding wire ropes could be 83 *mm* diameter galvanised 6x41 mooring wire, expected to cost approximately €^{2013} 45 per *m*, with minimum break loads and per *m* weights of approximately 582 *tons* and 29 *kg* per *m*, respectively (Gundersen, T. 2013).

Figure 58: Generic mooring chain (Zhang 2013)

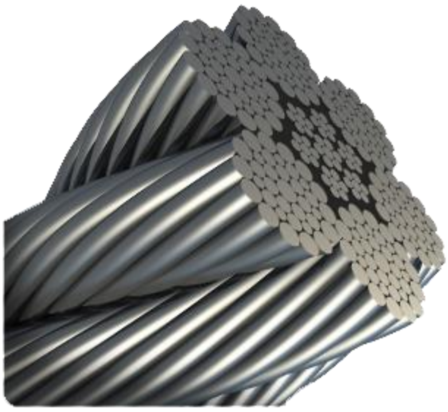


Figure 59: Illustration of generic mooring wire (Bridon 2013)

For the vertical mooring, SWAY AS prefers use of a steel pipe as a tension leg mooring line (Figure 60). Given the presented substructure mass, a minimum water depth of approximately 120 *m* is assumed, to account for wave interactions acting on the substructure (Jorde 2013; Myhr 2013). For 120 *m* water depth, this pile is estimated to be approximately 20 *m* long, have a diameter of approximately 1 *m* and a wall thickness of 50 *mm* (Jorde 2013), leading to per *m* pipe weights of approximately 1 170 *kg*, given S355 steel density of 7 850 kg/m^3.

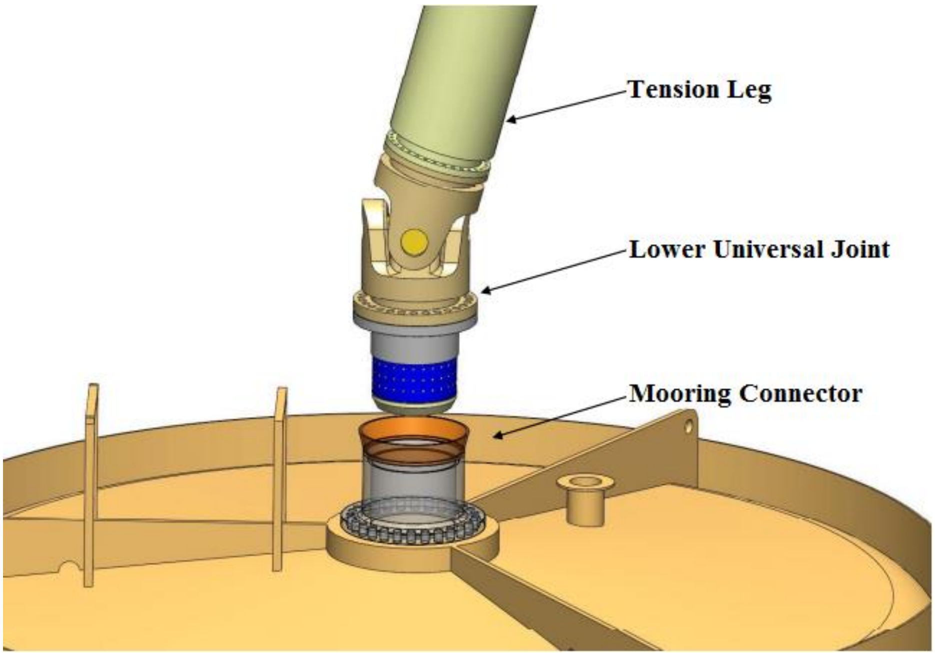


Figure 60: SWAY tension leg and mooring connector (Forland 2011)

As for taut leg mooring systems, constant stiffness is required independent of depth, but it is assumed much of this stiffness is provided by yaw bearings positioned near the bottom of the substructure (Jorde 2013). Accordingly, only a small linear increase in cross section area is assumed with increasing depths, culminating in 70 *mm* wall thickness at 500 *m* depths, giving an increase in cross section area of approximately 9.8 % per 100 *m* added depth.

Based on online information from Chinese steel vendors, production costs for steel pipes seem to be directly comparable to steel costs discussed in section 2.3.1 (Alibaba 2013a).

However, an addition of 50 % to bulk steel costs are assumed to account for welding operations in order to achieve adequate lengths for mooring pipes. Accordingly, the baseline costs for steel pipes used as tension mooring legs for vertical mooring are assumed to be approximately €^{2013} 1 890 per *m* for benchmark farm depths, with low and high case scenarios set to ± 27 % to account for steel price volatility.

Mooring line consumption

Based on mooring system type, the different concepts (Figure 61) are expected to consume different amounts of mooring lines, and these lines are expected to be of different types.

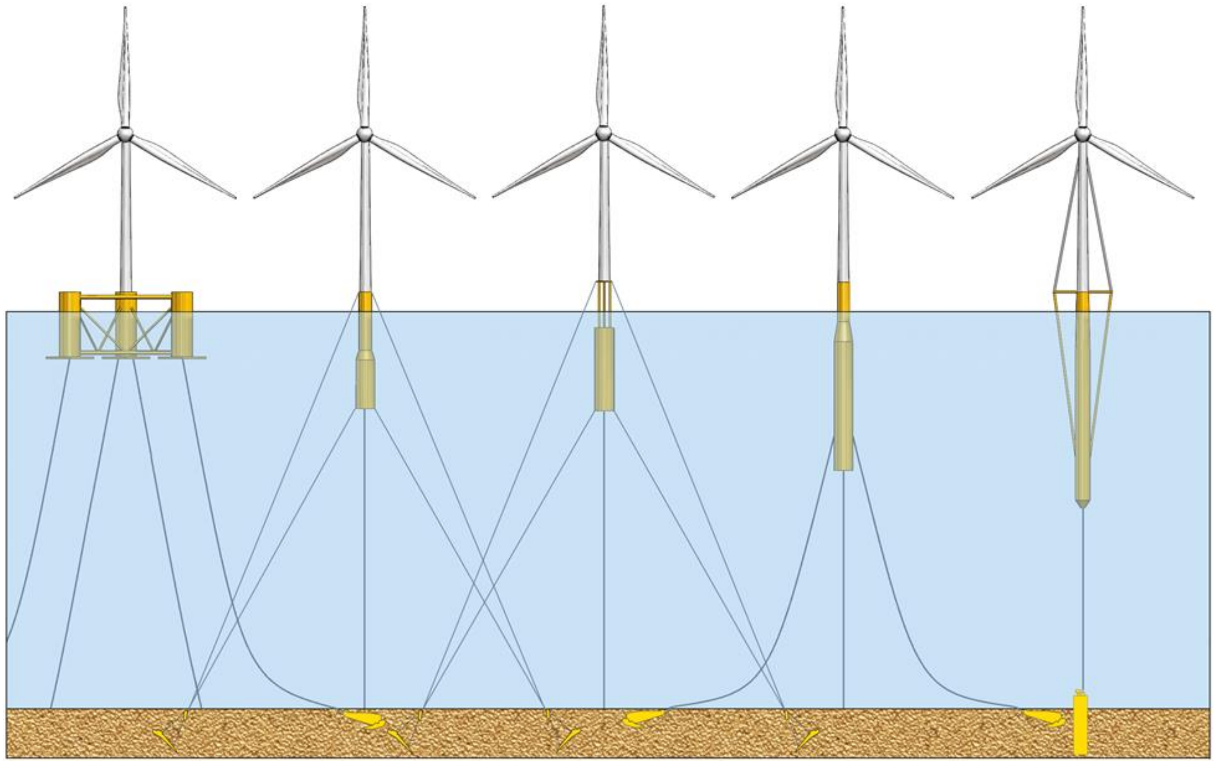


Figure 61: Floating concept illustration showing mooring system types. From left: WindFloat (catenary), TLB B and TLB X3 (taut leg), Hywind (catenary) and SWAY (vertical)

Selection of mooring radius and line length for concepts that use *catenary mooring system*, are results of fairly extensive simulations and optimisations for each concept at the selected site, and is not only depending on the water depth as a variable. In this thesis, we will make a simplification of the catenary mooring line length. For the Hywind concept we assume a line length of approximately 500 *m* for 100 *m* depth, and through a simplified approach, every 100 *m* additional depth leads to an increase of 150 *m* of mooring line length (Nygaard 2013). This assumption leads to a total length of 650 *m* for each catenary mooring line for the benchmark farm.

To account for draft differences of the WindFloat and Hywind concepts, each mooring line employed for the WindFloat concept is assumed to be 60 *m* longer than the Hywind mooring lines. For shallower water depths, the line length increases dramatically because of difficulties to obtain the preferred catenary shape of the mooring line. For catenary mooring systems, some clump weights may be required to be attached to the line in order to create the preferred shape. Near the mooring line point of soil penetration, some chain is required to create sufficient friction and to withstand long-term contact with the seabed, and for this thesis the chain consumption per mooring line is estimated to 50 *m* (Myhr 2013).

Selection of mooring line length for the concept that uses *vertical mooring system* is depending on the water depth as a variable. The SWAY concept has a draft just shy of 100 *m*. The 120 *m* minimum draft indicated for the SWAY concept indicates use of a tension leg pipe marginally shorter than the difference between the substructure draft and the water depth. Accordingly, for 200 *m* depth, a mooring line length of approximately 100 *m* is expected, increasing proportionally with water depth.

Selection of mooring radius and line length for concepts that use *taut leg mooring system* are depending on the water depth as a variable (linear function). The TLB concepts have mooring lines attached at two heights, at the bottom, 50 *m* below the water line, and at approximately 25 *m* over the water line. The upper line arrives the seabed at an angle of 45°, and for 200 *m* depth we assume a mooring system radius of 225 *m*. The upper and lower lines will then be approximately 318 *m* and 270 *m*, giving mooring line lengths just shy of 589 *m*.

Table 18 summarises the total length of mooring lines for each concept.

Table 18: Total benchmark length of mooring lines for each concept.

Concept	**TLB B / TLB X3 – 6 lines**	**Hywind - 3 lines**	**WindFloat – 4 lines**	**SWAY – 1 line**
Mooring line length	1 766 *m*	1 950 *m*	2 840 *m*	101 *m*

Total Mooring Costs

Table 19 summarises total costs related to acquisition of the mooring system for one unit of the discussed concepts, positioned at a benchmark depth of 200 *m*. Please note that these values do not include installation costs for the mooring systems.

Table 19: Floating concept mooring system acquisition costs per wind turbine, benchmark depth

Concept	**TLB B / TLB X3**	**Hywind**	**WindFloat**	**SWAY**
Anchors	3 x VLA	3 x DPA	4 x DPA	1 x SPA
Anchor costs	€^{2013} 834 000	€^{2013} 342 000	€^{2013} 456 000	€^{2013} 1 435 000
Fibre rope length	1 766 *m*	-	-	-
Chain length	-	1 800 *m*	2 640 *m*	-
Wire length	-	150 *m*	200 *m*	-
Pipe length	-	-	-	101 *m*
Mooring line costs	€^{2013} 1 077 000	€^{2013} 119 000	€^{2013} 169 000	€^{2013} 191 000
Total mooring costs	**€^{2013} 1 911 000**	**€^{2013} 461 000**	**€^{2013} 625 000**	**€^{2013} 1 626 000**

As indicated, the catenary mooring systems are expected to be the least expensive of the evaluated mooring systems, while the taut leg mooring systems are indicated to be the most expensive at benchmark farm depths.

3.2.4 Grid Connection

The purpose of the following section is to present capital acquisition costs of electrical equipment necessary to connect the wind farms to the onshore electrical grid. There are two basic types of cable used in an offshore wind farm; inter-array cables and export cables. Both types of cable are commercially available, have substantial track records and will be discussed in this section. In addition to cable discussion, use of offshore and onshore substations to reduce overall electrical losses in the wind farm will be discussed.

Inter-array Cable

The inter-array cable connects each turbine to the offshore substation. The turbine generator is commonly 690 V and an internal transformer steps up the voltage to the inner-array voltage (European Wind Energy Association 2011). The inter-array cables are typically standard medium-voltage equipment rated between 33 and 36 *kV*, but in the future some developers are considering the use of 66 *kV* cabling. The inter-array cable consists of three phase conductors, typically cobber or aluminium, an insulator and some kind of mechanical and chemical protection (The Crown Estate 2010).

Inter-array cables are generally relatively short cables. Depending on turbine size and spacing, the length between each tower is typically around 1 *km* (The Crown Estate 2010).

Larger distance between towers will lower the wake effects and higher the energy production per turbine, but at the cost of higher capital and operational expenditure and less energy production per unit seabed. It is therefore necessary to use reliable software tools to optimise the array layout for the lowest cost of energy. In our case, we simplify the wind farm layout to a square layout and set the row and column distance between the towers to 1 *km*. Generally, a minimum horizontal distance between towers in the range of 4 - 10 rotor diameters in the prevailing wind direction and 3 - 6 rotor diameters normal to said direction is advised to minimise wake loss effects (European Wind Energy Association 2009b; Kaiser & Snyder 2010). Positioning of the benchmark wind farms with the farm diagonal parallel to the most prevailing wind direction will satisfy mentioned horizontal distance requirements.

To avoid damages due to cable tension and to simplify the cable installation, the cable length between each wind turbine is in our benchmark cases set to be 1.6 *km*, as shown in Figure 62, an increase of 600 *m* with regards to the horizontal distance between the wind turbines. To account for varying depths, cable consumption between each wind turbine is set to 1 400 *m* plus the assigned water depth.

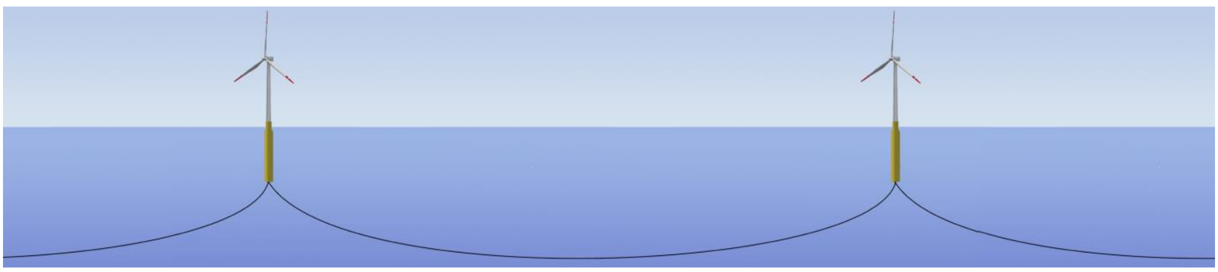
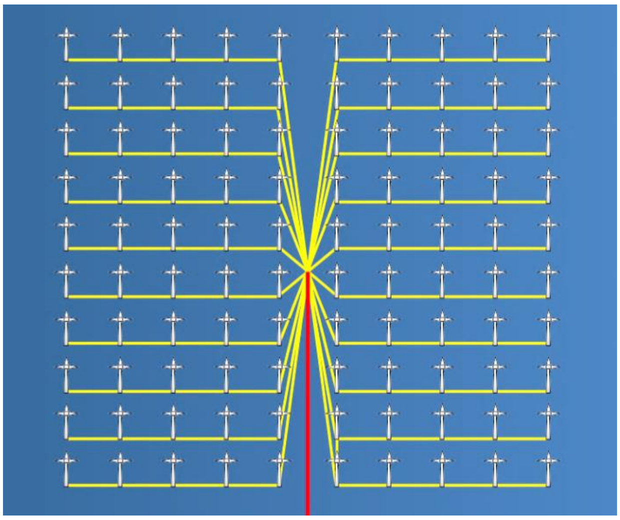


Figure 62: Cable length between each tower is set to 1.6 km

In Appendix 7, several inter-array structures have been discussed. The investigated structures are simplified and will most likely not represent a realistic inter-array layout, since deciding which inter-array structure to use for a certain wind farm is a highly site-specific operation. Nevertheless, the discussed structures will give us a reasonable cable consumption and corresponding electrical array losses needed to quantify our analysis. Figure 63 shows the inter-array cable structure that has been chosen for the benchmark farm. The towers are connected in series of five, with a total of twenty rows, giving a total benchmark cable length of 191.6 *km*.



Inter-array cable properties	
Total cable length	191.6 *km*
Cable type	33 *kV* cobber cable (300 mm^2)
Max power*	500 *MW*
Max percentage power loss	0.68 %
Average power*	224*MW*
Average percentage power loss	0.31 %

* Transmitted within the farm

Figure 63: Inter-array cable structure chosen for the benchmark wind farm, with the table showing key qualities related

Figure 63 summarises the maximum and average percentage power losses within the inter-array cable structure, estimated as through calculation methods presented in Appendix 7. The inter-array cable cross section area is set to 300 mm^2 as an average value, but for a real-life farm different portions of the inter-array cable structure may consist of either larger or smaller cables. The maximum power loss is calculated on the assumption that the total rated power of the entire wind farm is transmitted through the inter-array structure, while average power loss is calculated by evaluating power production with regards to expected average capacity factor and power losses. In section 2.2.3 we assume a load factor of 44.8 % (not taking into account losses in the cables and substation) which indicates that the average effect transmitted through the inter-array structure is approximately 224 *MW*. Based on this assumption, we have calculated the average effect loss to be 0.3 %.

(Douglas Westwood 2010) estimates the costs for 33 *kV* AC array cables (240 mm^2) to be approximately €^{2013} 190 000 per *km*, and (Kristensen 2013) estimates the costs for a 33 *KV* AC array cable (300 mm^2) to be approximately €^{2013} 325 000 per *km*. Based on these estimates, and assumptions that the costs of cables are proportional to the cable section area, the estimated baseline price is set to €^{2013} 281 000 per *km* (300 mm^2), leading to total inter-array cable costs for our benchmark farms to approximately €^{2013} 53.8 million. Low and high case scenarios for the array cable costs are set to ± 15 %. No apparent economies of scale with increasing farm size are assumed, and with increasing farm sizes, it is assumed farms consist of individually positioned clusters of 100 turbines, connected to an export hub.

Export Cable

The export cable stretches from the offshore substation and to the onshore electrical transmission system. The export cable consists of a conductor, typically cobber or aluminium, an insulator and some kind of mechanical and chemical protection. The cable could either be an AC export cable which consists of three phase conductors or a typical DC export cable which consists of two single-core conductors, meaning that the DC cables are lighter and therefore cheaper for a given capacity (The Crown Estate 2010).

Most offshore wind farms are today relatively close to shore and uses AC export cables. HVAC cables suffer significant losses over longer distances due to reactive power flow, and the cables have therefore a limitation of about 150 *km*. HVDC cables is used for long distance transmission, mainly since the full capacity of the cable system can be used for transferring active power. If HVDC cables are chosen, an expensive offshore substation is needed and the savings from the use of these cables are not realised until they are around 80 *km* long (The Crown Estate 2010). With the advantages for subsea power transmission and recent developments in power electronic conversion, the use of HVDC cables has become a more attractive option for longer distance and larger wind farms. In addition, the economics of the technology is expected to improve over the next decade due to learning and scale effects (European Wind Energy Association 2011). Figure 64 gives an indication of the limits of AC transmission and when DC is preferred.

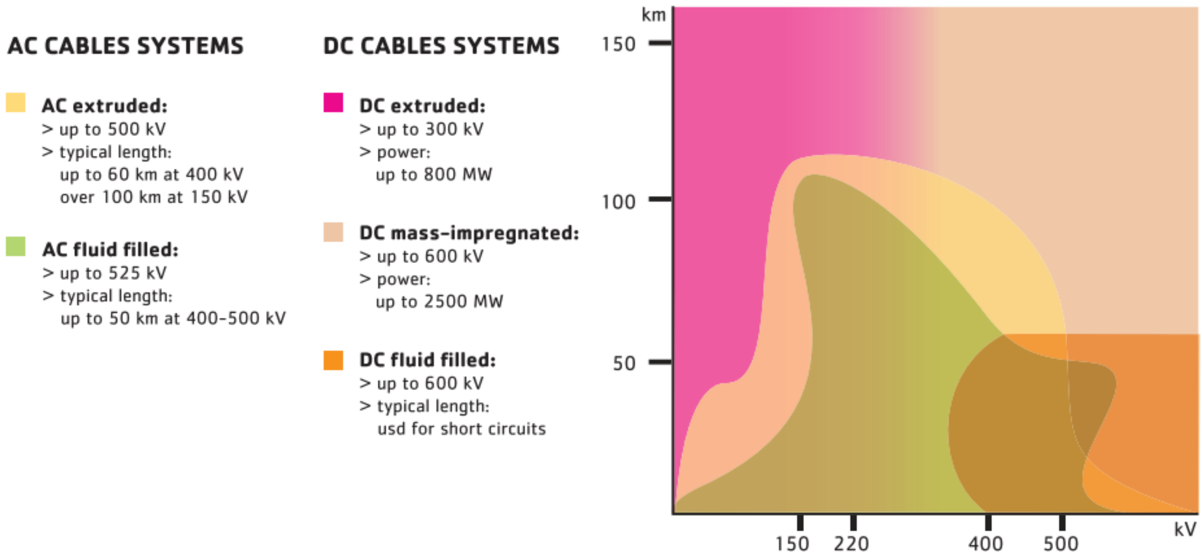


Figure 64: Technology capabilities for power transmission (Prysmian Powerlink Srl 2012)

AC export cables are typically rated at 132 *kV*, but in some cases it has been deployed 245 *kV* cables. The longest AC export cable is the Isle of Man connector, a 90 *kV* cable transferring 40 *MW* on a distance of 104 *km*. For DC cables, we differentiate between extruded and mass-impregnated cables. Extruded cables are less expensive than mass-impregnated cables, and are typically rated between 150 *kV* and 320 *kV*. For this rating, each cable is capable of transferring up to approximately 800 *MW*, as shown in Figure 64. Mass-impregnated cables are preferred with increasing power transmission (Bahrman 2011)

Deciding which cable to use for a certain wind farm is a highly site-specific operation, and finding an optimal balance between capital expenditures for the cable and costs from ohmic losses in the cable based on offshore distance and site-specific conditions impacting energy production is key. For our benchmark farms, attached calculations (Appendix 7) have indicated use of one 320 *kV* HVDC extruded cable with a cross-sectional area of 1 500 mm^2 favourable in terms of lowest present equivalent of cable costs and energy loss costs, both from ohmic cable losses and losses coming from occurrence of complete downtime of farm due to export cable failure. Average losses are estimated to 0.5 %.

In Appendix 7, the price for this type of cable is indicated to be between €^{2013} 354 000 – 531 000 per *km*, indicating a baseline export cable cost of €^{2013} 88.6 million for the thesis benchmark wind farm site (National Grid 2011). Figure 65 shows a typical cross section of an HVDC export cable.

Figure 65: 200 kV HVDC Extruded 1x1100 mm^2 Submarine Cable (Prysmian Powerlink Srl 2012)

Offshore Substation

The offshore substation is used to increase the voltage prior to exporting the power to shore, and therefore reducing electrical losses. Generally it is no need for an offshore substation if the wind farm is 100 *MW* or less, the distance to shore is 15 *km* or less, or the connection to the grid is at collection voltage (Douglas Westwood 2010).

Abstracted from Joule's first law and Ohm's law, delivered electric power P is given by as the product of voltage E and current I from the relation $P = EI$, meaning that when transferring a certain power, increase of grid voltage will lead to decline in grid current. As explained in Appendix 7 ohmic power losses P_{loss} dissipated in a cable are given as a product of the current I squared and the total cable resistance R of the cable, $P_{loss} = I^2R$. To transfer a certain power, it is therefore desirable to increase voltage in order to reduce current, which in turn diminishes cable power losses. For a wind farm far offshore, it is by that reasoning wise to increase voltage in the farm before transferring power through an export cable to shore, and this is done in the so-called offshore substation. These substations are expensive, but when taking into consideration that medium voltage cables are unable to transfer powers exceeding 30 - 40 *MW*, high capital costs for offshore substations pay off for large structures far offshore due to lower energy losses and fewer cables needed to transport the energy to shore (European Wind Energy Association 2011).

In addition to increasing voltage, substations may convert current from AC to DC. Offshore substations traditionally consist of electrical equipment needed to convert current and transform voltage, such as switchgears, transformer, converter, cabling etc., as is the case for land-based equivalents, but also contains extra protection to cope with the demanding offshore environment. Substations may also include vessel docking solutions, storage and maintenance facilities, helicopter decks, safety and fire equipment etc. (Lazaridis 2005).

Two main HVDC transmission technologies exist, *Current Source Converters* - CSC (also denoted *Line Commutated Converters)*, and *Voltage Source Converters* - VSC. HVDC CSC technology is a well proven technology has been deployed since the 1970s, and is based on external AC voltage to convert current. HVDC VSC technology requires no independent power source to convert current, resulting in VSC technology converters being roughly half the size of CSC technology, and therefore much better suited to be deployed on offshore platforms. Today, VSC technology is limited with regards to transmission capacity, relative to CSC technology, but increased focus on development of VSC technology results in significant increases in expected power rating. (National Grid 2011)

Power engineering giant ABB has been a pioneer in using HVDC technology for power transmitting purposes for more than fifty years, and introduced their *HVDC Light* system, based on underground power transmission in 1997. In 2009, BorWin 1, the world's first HVDC connection for wind power was installed on a jacket structure at the BARD Offshore 1 wind farm off the German North Sea coast. The connection consists of sea-land cables and BorWin Alpha (Figure 66), a converter substation, rated to 400 *MW*, where 36 *kV* AC was transformed to 155 *kV* AC before conversion to ± 150 *kV* DC. Power is transmitted to the mainland via two 125 *km* subsea cables and through the Wadden Sea and onshore by two 75 *km* cables. The topside dimensions of the converter substations are approximately 50 x 35 x 20 *m*, with a topside weight of approximately 3 200 *tons*. (Jones 2009)

Figure 66: BorWin Alpha (Jones 2009)

For our benchmark farm, a 500 *MW* HVDC platform including AC switchgear, transformers, converter electronics and filters is assumed. The total number of substations and the capacity of the substation that is required for increasing the farm size will be further discussed in Appendix 8. In this thesis, we further distinguish between bottom-fixed and floating substations, since they will have different substructures. This is also discussed in Appendix 8. The total acquisition costs for a bottom-fixed substation costs (excl. installation) are assumed to be approximately €^{2013} 143.0 million, and €^{2013} 161.7 million for a floating substation.

Average losses in the substation are set to 1 % (National Grid 2011), giving overall electric offshore losses of approximately 1.8 %.

Onshore Substation

The onshore substation is used to transform the exported power to the grid voltage at land. If the export cables are HVDC, the substation will convert the power to three phase AC.

Figure 67 shows the onshore substations at the Norwegian side of the 700 *MW* NorNed HVDC cable system, connecting the Norwegian and the Dutch electricity grid (Tubaas & Olsen 2011).

Figure 67: Feda station, onshore substation for the NorNed subsea power cable system (Tubaas & Olsen 2011)

(The Crown Estate 2010) estimates the cost for an onshore substation to be approximately half of the cost of the offshore bottom-fixed substation. For our benchmark wind farm, the total costs for an onshore substation including installation is assumed to be approximately €^{2013} 71.5 million.

3.3 Installation and Commissioning

In this section, we aim to estimate total installation costs for the wind farms, which comes from transport to site and installation of all substructures, turbines, cables (inter-array and export cables) and offshore substations. Costs are assumed to be for generic equipment. Wind farm commissioning costs, i.e. costs associated with finalisation and testing of the wind farm are assumed to be included in the presented costs.

3.3.1 Substructure and Turbine Installation Method Overview

Assembly Locations

Generally, we may differentiate between three main assembly locations for offshore wind turbines. Components can be assembled into wind turbines either onshore, in calm and protected waters near shore, offshore at installation site, or by a combination of these. In general, the installation process of substructures and turbines could be divided into the following processes:

1. Quayside loading of components onto utilised transit vessel
2. Transit voyage from port to site
3. Installation of component at site
4. Voyage to next installation site
5. Repetition of installation and voyages until all loaded components are installed
6. Transit voyage from site to port, in order to repeat process

Specialised Vessel Use

When using specialised installation vessel for installation at offshore site, we may differentiate between two strategies for use of a specialised installation vessel, so-called *feeding* and *transiting* (Figure 68). The installation vessel may either be fed wind turbines or wind turbine components by smaller vessels which travel back and forth from construction port to the installation site, or the installation vessel may self travel back and forth from port to site. The latter method, transiting, requires few other vessels than the specialised installation vessel, but is both more time-consuming than the feeding strategy, and also utilises less of the vessel's specialised capacities. However, historically the transiting method has been preferred when installing large, commercial wind farms. (Bard & Thalemann 2011)

For this thesis, it is decided that for the floating concepts, specialised vessels as much as possible are fed by smaller vessels when evaluating installation operations at offshore site, despite being potentially more risky than the transiting method because of offshore transfers. The reason behind using the feeding method is both because the benchmark farm is positioned so far offshore the total rent associated with one trip to and from benchmark site positioned 200 *km* offshore approaches nearly €^{2013} 350 000, when assuming a transit speed of 14 *knots*, similar to that of *Oleg Strashnov*. These costs do not include on- and offshore loading etc., only transit times. Similar operations performed with a PSV, with transit speeds of 18 *knots* and baseline day rates of €^{2013} 46 000, are expected to cost approximately €^{2013} 26 000. Taking into account the deck space, indicating an area capacity similar to the assumed capacity of the cheaper PSVs, it seems unreasonable to have a specialised vessel in shuttle service between port and site. (Gusto MSC 2012)

Figure 68: Specialised vessel use: Feeding (blue) and transiting (green)

For bottom-fixed concepts different assumptions are made, seeing as jack-up vessels may be utilised. Due to the ratio between the presence of crane vessels and purpose-built jack-up vessels, jack-up vessel day rates tend to be more reasonable than those of crane vessels (Midtsund & Sixtensson 2013). Additionally, jack-up vessels tend to have deck space for a considerable number of turbines or foundations, e.g. either nine turbines or foundations per trip for MPI Resolution, the first of several jack-up vessels purposely built for wind farm installations (MPI Offshore 2011). Increased deck capacity and specialised design leads to assumptions that the transiting method is used for installation of bottom-fixed concepts, reducing offshore transfer lift hazards.

Turbine Installation

Turbines traditionally consist of at least seven individual components: nacelle, hub, three rotor blades and two tower sections, which can be transported and installed in a number of ways ranging from transporting the individual components to site before lifting them in place with several lifts, to assembling the complete turbine on or near shore before transportation and a single, heavy lift onto the substructure.

Which installation course that is chosen depends on the total costs of the operation, which are affected by a number of variables, e.g. number of lifts, crane capacity both on- and offshore, deck area utilisation etc. Kaiser & Snyder (2010) operate with turbine installation strategies where the number of lifts range from one (complete turbine assembled near shore before being lifted onto the substructure) to six (all parts are installed separately onto the substructure, except the nacelle and hub, which are assembled prior to installation). With increasing number of lifts, the total offshore installation time per turbine may increase, but the necessary capacity of the crane and of the near-shore infrastructure is reduced. Based on data from 17 European wind farm installations, a strategy involving a total of four lifts: two tower sections, nacelle and complete rotor (Figure 69) has been the preferred turbine installation strategy in more than 40 % of the cases. (Kaiser & Snyder 2010)

Figure 69: Installation of a preassembled rotor at Alpha Ventus (Wilmert 2013)

It is important to point out that preferred turbine installation strategy is extremely site- and time-specific, depending on both wind and wave conditions. Lifting and installing a complete rotor could be more challenging than installation of a nacelle because of the ratio between weight and area affected by wind, which putting severe constraints on the maximum wind speeds during which the lifting operations can be performed, leading to smaller operational windows. Finding the right turbine installation strategy for a certain offshore site requires planning from actual site data, and it is by no means certain that the optimal strategy found for a given site at a given time will be optimal for another site or even for the given site at a different point of time. Naturally, it is important to realise that if an offshore wind project similar to the ones discussed in this thesis were to be executed at a specific site, turbine installation strategies would have to be evaluated with close attention to site-specific detail, leading to costs that may be higher or lower than those presented in this thesis. (Midtsund & Sixtensson 2013)

3.3.2 Installation of Bottom-fixed Concepts

For bottom-fixed wind turbines, the foundation and transitional piece are traditionally installed before connecting the turbine to the installed foundation. These tasks can be done by traditional crane vessels, but are commonly done using highly specialised wind turbine installation vessels, based on jack-up technology.

Based on data from commercial-scale wind farm projects in Northern European waters, an average installation time of 2.6 boat days per monopile is indicated (Kaiser & Snyder 2010). These numbers include transit time and weather delays. Not accounting transit and quayside loading, and taking learning curves into account, an expectation of a total of three days per substructure is assumed. Seeing as jacket structures have mainly been deployed for pilot projects (Lindø Offshore Renewables Center 2013), resulting in lack of data, assumptions of 24 extra installation hours for jackets relative to monopiles are set. Jacket installations require piles to be driven into the seabed, and these piles are smaller, but more plenteous than the number of piles requiring driving operations for monopiles, leading to piling activity durations sometimes more than 2.5 times those of monopile piling durations (Degraer et al. 2013; Kaiser & Snyder 2010).

Further, a deck capacity of nine monopile substructure components or turbines, and a total of three hours per lifting operation at quay is assumed. Each monopile substructure consists of a transition piece in addition to the actual pile, resulting in two quayside lifts required for each monopile substructure. The fact that monopile substructures consist of two components with similar outer dimensions, leads to assumptions that the vessel is able to transport nine sub-structure components, resulting in total transit cost from port to average distance at wind farm site to be evaluated as evenly distributed between the components, based on transit speeds of 11 *knots* (MPI Offshore 2011). For simplicity, the physical dimension of jackets and the presence of smaller piles leads to assumptions that monopiles and jackets may be evaluated equal with regards to lifting operations and deck capacity. Operational windows are expected to be 75 % for quayside lifts and transits, and 50 % for offshore installation operations (Myhr 2013).

Based on real-life data from large-scale bottom-fixed projects, an approximate turbine installation time excluding loading, transit and *Waiting on Weather* (WoW) is set to 1.2 days, based on experienced industry record installation times at Thanet Wind Farm and economies of learning into consideration for industry averages (Kaiser & Snyder 2010; Vestas 2012). Per-turbine installation costs are based on an assumption that a turbine can be loaded in four hours. Operational windows are expected to be 80 % for quayside lifts and transits, and 50 % for offshore lifting installation operations (Myhr 2013).

A number of additional workers apart from crew supplied with the vessel are necessary to perform certain mechanical and electrical attachment operations. Installation operations are assumed to require 15 employees working 12-hour shifts, leading to a total of 30 workers employed per day (DEME 2013), each paid day rates of €^{2013} 370.

Expected installation costs per wind turbine for both monopile and jacket substructures are presented in Table 20 and Table 21, respectively. Please note that these values are mere estimates for installation costs when using a high-capacity jack-up vessel, and that costs would be affected by changes in installation time and vessel qualities.

Table 20: Estimated installation costs for monopile wind turbines

Installation operation	Operation	Value	Duration	Unit cost	OW	Total cost
Jack-up Substructure installation	Quayside lifts	2.00	0.13	€ 196 000	75 %	€ 65 000
	Transportation	0.22	0.82		75 %	€ 48 000
	Substructure installation	1.00	2.00		50 %	€ 784 000
	Personnel usage	30.0	2.94	€ 370	52 %	€ 61 000
Jack-up Turbine installation	Quayside lifts	1.00	0.17	€ 196 000	80 %	€ 41 000
	Transportation	0.11	0.82		80 %	€ 22 000
	Turbine installation	1.00	1.20		50 %	€ 470 000
	Personnel usage	30.0	2.18	€ 370	54 %	€ 45 000
Total installation cost per wind turbine						**€ 1 492 000**

Table 21: Estimated installation costs for jacket wind turbines

Installation Operation	Operation	Value	Duration	Unit cost	OW	Total cost
Jack-up Substructure installation	Quayside lifts	2.00	0.13	€ 196 000	75 %	€ 65 000
	Transportation	0.22	0.82		75 %	€ 48 000
	Substructure installation	1.00	3.00		50 %	€ 1 176 000
	Personnel usage	30.0	3.94	€ 370	52 %	€ 84 000
Jack-up Turbine installation	Quayside lifts	1.00	0.17	€ 196 000	80 %	€ 41 000
	Transportation	0.11	0.82		80 %	€ 22 000
	Turbine installation	1.00	1.20		50 %	€ 470 4000
	Personnel usage	30.0	2.18	€ 370	54 %	€ 45 000
Total installation cost per wind turbine						**€ 1 906 000**

Additionally, each wind turbine has to be assigned its portion of the total mobilisation costs for the jack-up vessel, set to four day rates divided by the number of installed wind turbines. Total wind turbine installation costs for the benchmark monopile wind farm are, given our assumptions, estimated to approximately $€^{2013}$ 50 million, corresponding to $€^{2013}$ 300 000 per *MW*. For the benchmark jacket wind farm, corresponding numbers are approximately $€^{2013}$ 191.4 million and $€^{2013}$ 383 000. Installation costs are assumed to be proportional with wind farm size with regards to all aspects except mobilisation costs.

The numbers suggest installation of jacket-based wind turbines are expected to be approximately 28 % more expensive than installation of monopile-based wind turbines, adding to assumptions that monopile-based farms from an economical point of view are likely to be preferred over jacket-based farms if site qualities allow them. If depths exceed 30 *m*, monopile structures are expected to lose their economical advantage through technical limitations (Borgen 2010)

3.3.3 Installation of Floating Concepts

Depending on floater concept, floating wind turbines may be installed in a number of proven or experimental methods. Variables include transport orientation of components such as towers and floaters, degree of assembly prior to transportation to installation site and whether components or wind turbines are to be towed or transported on deck of a transportation vessel.

According to Kjartan Melberg, CEO of Norwegian wind turbine installation and O&M contractor Inwind, turbine manufacturers warn about assembly of tower and nacelle prior to horizontal transport of turbines. These objections come from the fact that the walls of the towers are expected to be compromised by the weight of the nacelle (Melberg 2013). Accordingly, installation strategies based on horizontal transport of joined towers and nacelles will not be evaluated for this thesis.

Installation Strategies

Two main installation strategies for floating concepts are to be presented, where one is based on complete installation near-shore before towing the complete wind turbine to site, and one is based on towing the substructure, with or without the turbine tower attached prior to towing, to offshore site where turbine components are installed. Both main installation strategies vary depending on turbine lift strategies, i.e. the number of lifts performed to completely install the turbine

Towing of Complete, Vertical Wind Turbines

Complete assembly of floating wind turbines in calm waters or onshore (i.e. in a dry dock) prior to tug transportation to site has been the preferred installation method for operational pilot turbines as of early 2013. The Hywind pilot turbine was erected and installed as follows (Statoil ASA 2010):

1. The floater was produced at Technip's yard in Pori at the Southwestern Finnish coast, before being horizontally towed to the assembly site in Åmøyfjorden near Stavanger, Norway.
2. The floater was temporarily ballasted using sea water and erected, before being locked at a crane barge.
3. The floater was permanently ballasted by the crane barge, which collected the olivine ballast from a supply ship.
4. A second crane barge attached the lower tower part to the floater.
5. The upper tower and the nacelle, pre-assembled on dry land, was collected on dry land and transported by the second crane barge before being assembled onto the floater.
6. The rotor, pre-assembled on dry land, is accordingly mounted on the nacelle using the second crane barge.
7. The complete wind turbine was towed to site using an AHTS assisted by two conventional tug boats in good weather conditions.
8. Three anchors were installed by the AHTS prior to mooring of the wind turbine.

This method removes the need for dangerous, heavy lifts at sea, and as associated with larger operational windows due to milder weather conditions in protected waters. The method requires near- or onshore cranes for assembly and AHTSs and tug boats for towing and mooring, and is presented in Figure 70.

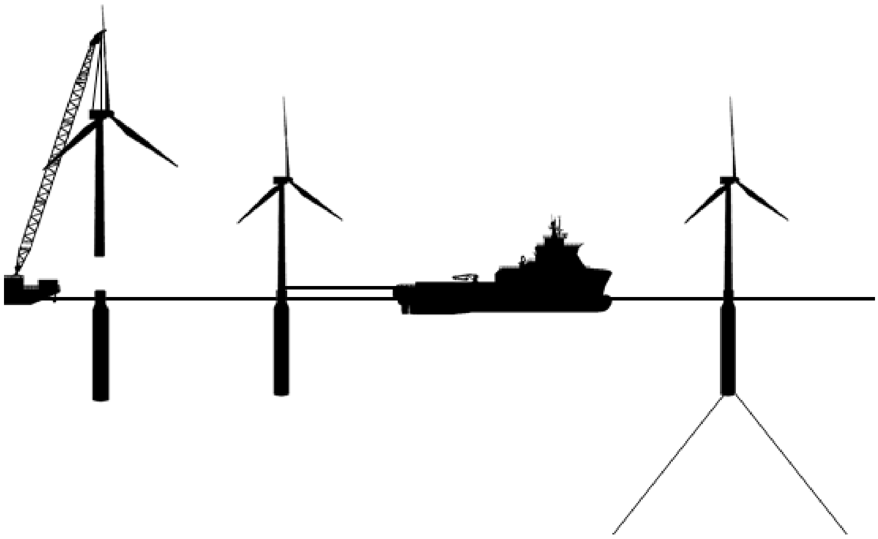


Figure 70: Vertical towing of complete wind turbines from shore (left) to site (right)

Quay facilities adapted to quayside installation of turbines onto floaters, e.g. by having drafts exceeding floater drafts at quay, could lower these installation costs even further by not having to rely on crane barges, only land-based equipment. Figure 71 shows how PrinciplePower envision possible large-scale installation of their modest draft WindFloat concept.

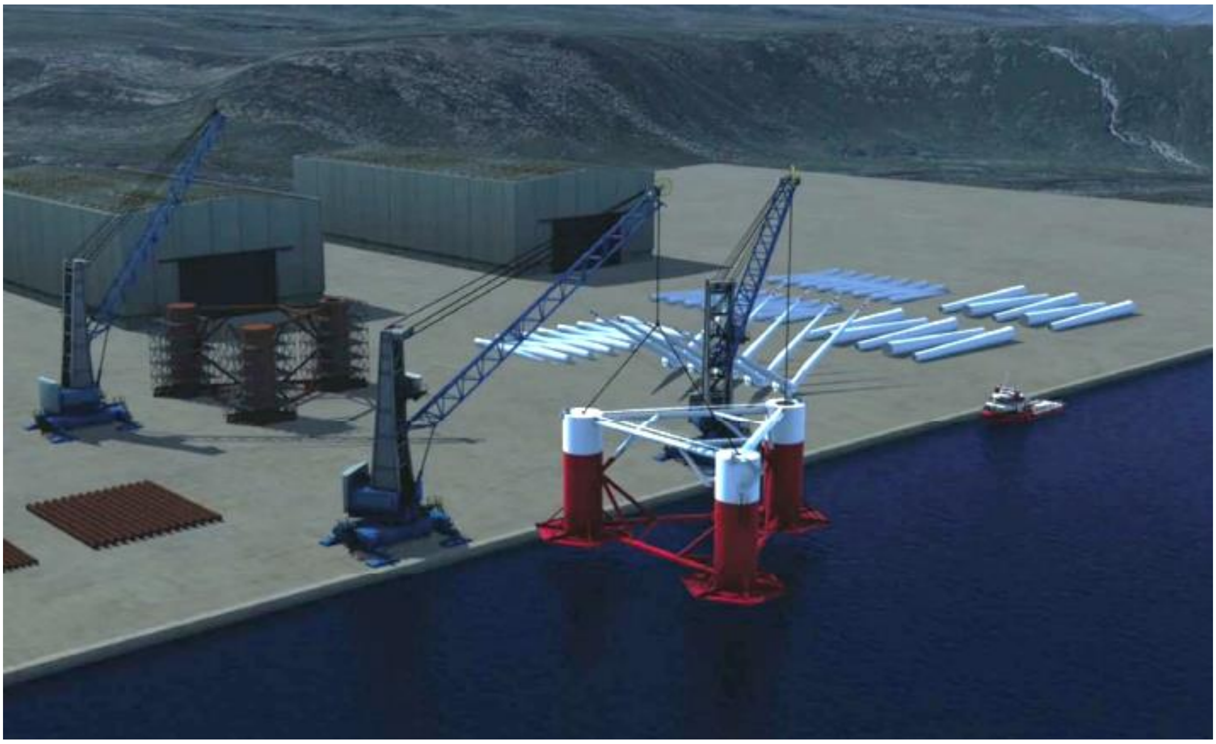


Figure 71: Envisioned large-scale installation of turbines onto WindFloat concept substructures (Weinstein 2009)

Transport of Floater or Floater and Tower Configuration

Another possible installation strategy is to tow an adequately sealed floater or a preassembled floater and tower configuration to site using an AHTS assisted by tug boats. On site, a crane vessel installs the remaining turbine components, which have been transported to site using a PSV.

The installation methods are illustrated in Figure 72 and Figure 73, respectively for towing of floater and preassembled floater and tower configuration. Figure 72 illustrates towing of floaters, while Figure 73 illustrates towing of integrated floater and tower configurations, preassembled during production.

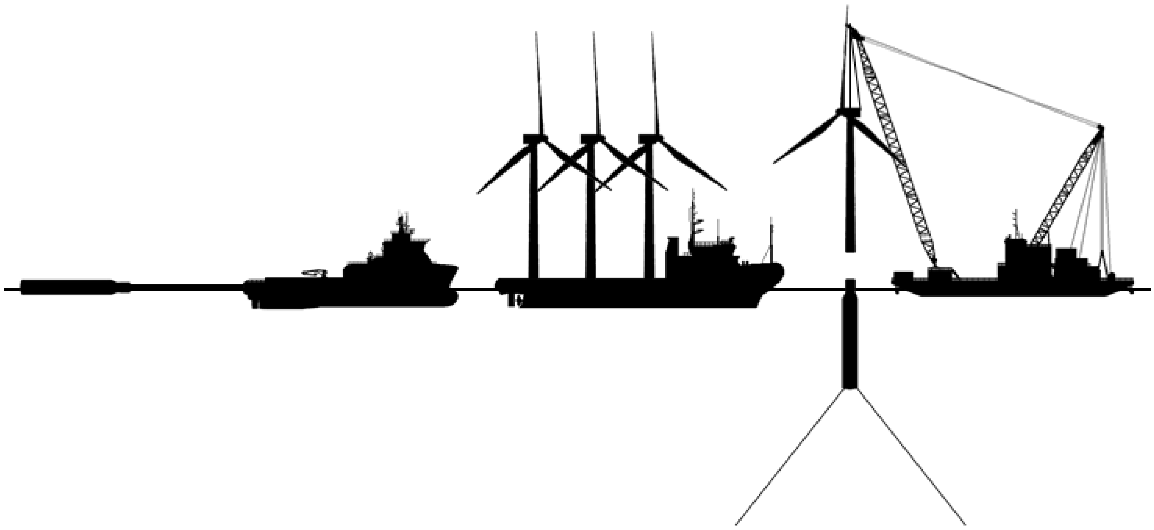


Figure 72: Transport of floater from shore (left) to site (right)

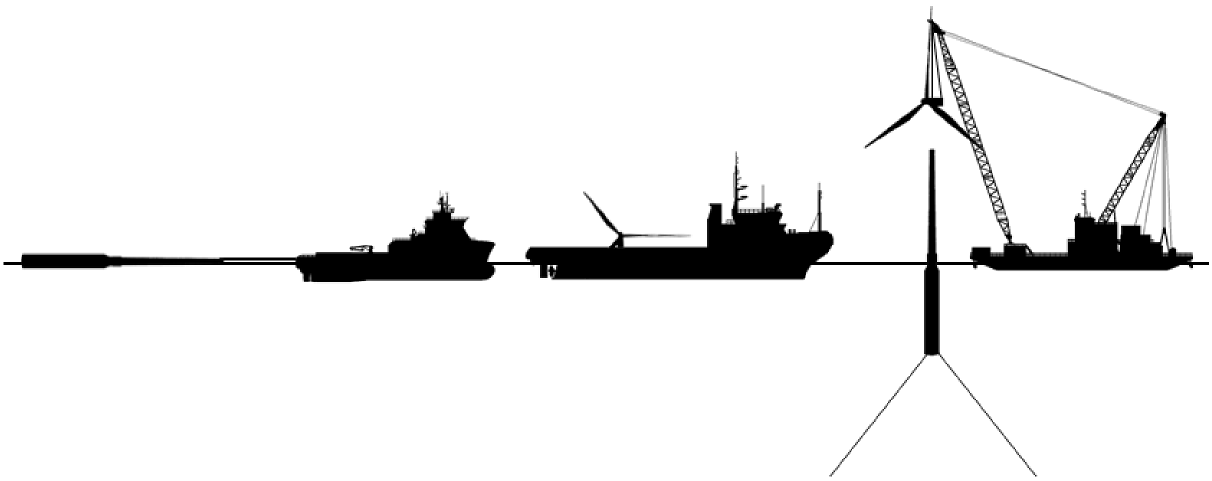


Figure 73: Towing of floater and tower configuration from shore (left) to site (right)

Installation Strategy Costs

Here we intend to estimate installation costs for floating substructures and turbines based on three different installation strategies, each divided into three turbine lift strategies denoted A to C. After finding installation costs per strategy, each concept is assigned its most economically favourable strategy.

A set of assumptions on personnel usage, operational windows, transit capacities and speeds are made:

1. Taking around-the-clock operations into account, a total of 30 personnel who are not covered by vessel day rates are assumed to participate in the lifting operations, based on information that approximately 15 additional workers besides vessel crew at all times assist with mechanical and electrical operations during installation (DEME 2013). These costs are assigned to crane vessel use
2. All quayside turbine lifts are assumed to take two hours, double when lifting complete turbines. Operational windows are assumed to 75 %
3. Floaters may be launched a number of ways, including lifts, flooding of docks or sideways launch, and the average costs of these methods are assumed to be equivalent to one quayside lift lasting two hours, with an operational window of 80 %
4. Up-ending of the floater is assumed to take 12 hours, applying to all concepts except WindFloat. The operations are handled by assistance vessels, with an assumed operational window of 60 %
5. The AHTS is expected to sail at different speeds and have different operational windows based on which installation operation is being performed on which concept, taking into account that the concepts are expected to differ in weight and stability. Large weight is expected to negatively affect tow speeds, with the exception of WindFloat, which is expected to be towed at higher speeds than the different concepts. High stability is expected to positively affect operational windows, with high values for WindFloat and Hywind, gradually declining to the most unstable concepts, the TLB concepts. All assumptions are shown in Table 22, based on correspondence with (Myhr 2013). Note that *Speed* indicates towing speed in *knots* and OW indicates percentage operational window

Table 22: Concept-depending speeds and operational windows for AHTS vessels

Concept	**TLB B**		**TLB X3**		**Hywind**		**WindFloat**		**SWAY**	
Operation	Speed (*knots*)	OW (%)	Speed (*knots*)	OW (%)	Speed (*knots*)	OW (%)	Speed (*knots*)	OW (%)	Speed (*knots*)	OW (%)
Own transport	15	90	15	90	15	90	15	90	15	90
Towing complete turbines	4.5	45	4.5	45	3	50	5	55	3.5	45
Towing floater and tower configuration	5.4	50	5.4	50	4.2	55	6	65	3.9	60
Towing floater	5.9	65	5.9	65	4.6	60	6.5	70		

6. The AHTS is expected to be able to tow one complete wind turbine or two floaters or floater and tower configurations, regardless of concept. All towing operations are assisted by two tug boats
7. The PSV is assumed to have a transit speed of 18 *knots* / 33.3 *km/h* (assumed operational window 70 %), with an ability to carry three turbines per trip (Raadahl & Vold 2013)

8. Ballast of Hywind, SWAY and WindFloat concepts are expected to last 24 hours, handled by the near- or offshore crane vessel. Operational windows offshore are set to 60 %
9. Given less harsh conditions operational windows, near-shore operational windows are amped 20 % in relation to offshore operations
10. Attaching of the floater to the mooring system is assumed to be handled by an AHTS, taking a total of six hours per line, with an operational window assumed at 55 %
11. The offshore crane vessel is assumed to require four hours of rigging and transportation between each installation operation, while the corresponding figure for the near-shore crane barge is two hours. Respective operational windows are assumed to 65 % and 75 %

Based on data from *Oleg Strashnov*, the vessel is assumed to be able to perform basic lifting operations in significant wave heights up to 2.5 *m* and wind speeds of 17 *m/s* (Gusto MSC 2012). Accounting only for wave heights, an operational window of approximately 59 % is expected (Faltinsen 1990). However, the operational window based on wind speeds is expected to vary depending on turbine installation strategies, e.g. lifting of individual rotor blades is more demanding than lifting nacelles, as the relation between total area affected by wind and component weight decreases (Midtsund & Sixtensson 2013). Accordingly, a set of offshore lift operational windows assumptions are made, based on an expected Weibull distribution of wind speeds corresponding to an average wind speed equal to that of our benchmark site, positioned at a generic North Sea site (Bierbooms 2010). The approximate maximum operational wind speeds and expected operation durations are based on information from (Midtsund & Sixtensson 2013) and (DEME 2013). Time consumptions are assumed to include lift mobilisation, and wave height limitations are employed when maximum operation wind speeds indicate operational windows larger than that from (Faltinsen 1990). These values are presented in Table 23.

Table 23: Offshore lifting operation qualities

Component lift	**Time consumption**	**Maximum operational wind speed**	**Operational window**
Individual rotor blade	4 *hrs.*	8 *m/s*	43 %
Assembled rotor	5 *hrs.*	8 *m/s*	43 %
Nacelle	4 *hrs.*	10 *m/s*	58 %
Tower	6 *hrs.*	12 *m/s*	59 %
Complete turbine	12 *hrs.*	7 *m/s*	35 %

Based on the different lift times and corresponding operational windows, expected time consumption and weighted operational window for the three turbine lift strategies are computed and shown in Table 23. Near-shore lifts are evaluated as equally time-consuming, but milder weather conditions are taken into consideration through less lenient operational windows.

Table 24: Offshore lifting operation time consumption and operational windows

Turbine lift category / number of lifts	Lifting operations	Time consumption given perfect weather	Weighted OW	Expected actual time consumption
A/5	• Tower • Nacelle/hub • Individual blades	22 *hrs.*	49 %	45 *hrs.*
B/4	• Preassembled floater and tower configuration • Nacelle/hub • Individual blades	16 *hrs.*	46 %	35 *hrs.*
C/3	• Tower • Nacelle/hub • Rotor	15 *hrs.*	52 %	29 *hrs.*
D/2	• Preassembled floater and tower configuration • Nacelle/hub • Rotor	9 *hrs.*	48 %	19 *hrs.*
E/1	• Complete turbine	12 *hrs.*	35 %	34 *hrs.*

Based on these turbine lift strategies (strategies A-E) and whether final installation of the turbine is to be performed near shore (installation strategy 1) or offshore (installation strategy 2), a total of ten installation strategy costs will be evaluated. These are as follows:

- 1A: five turbine components lifted onto floater near shore.
- 1B: four turbine components lifted onto floater and tower configuration near shore.
- 1C: three turbine components lifted onto floater near shore.
- 1D: two turbine components lifted onto floater and tower configuration near shore.
- 1E: complete turbine lifted onto floater near shore.
- 2A: five turbine components lifted onto floater offshore.
- 2B: four turbine components lifted onto floater and tower configuration offshore.
- 2C: three turbine components lifted onto floater offshore.
- 2D: two turbine components lifted onto floater and tower configuration offshore.
- 2E: complete turbine lifted onto floater offshore.

Strategy-dependant installation costs

Here, concept installation costs for vertical towing of wind turbines assembled near shore (Figure 70) will be presented depending on turbine lift categories. Cost calculations are presented in Digital Appendix 1, while cost discussions are presented in Appendix 9.

Table 25 summarises concept installation costs for the evaluated installation strategies based on different turbine lift strategies, given our stated assumptions. These costs also include assigned mobilisation lump sums.

Table 25: Per wind turbine concept installation cost estimates for the evaluated strategies. All values in €2013

Strategy	TLB B / TLB X3	Hywind	WindFloat	SWAY
1A	€ 860 000	€ 878 000	€ 736 000	€ 747 000[1]
1B	€ 818 000	€ 836 000	€ 700 000	€ 705 000
1C	€ 799 000	€ 817 000	€ 681 000	€ 686 000[1]
1D	**€ 768 000**	**€ 786 000**	***€ 644 000***	**€ 655 000**
1E	€ 804 000	€ 822 000	€ 680 000	€ 691 000[1]
2A	€ 2 082 000	€ 2 825 000	€ 2 738 000	€ 2 730 000[1]
2B	€ 1 952 000	€ 2 702 000	€ 2 555 000	€ 2 585 000
2C	€ 1 585 000	€ 2 328 000	€ 2 241 000	€ 2 233 000[1]
2D	€ 1 308 000	€ 2 040 000	€ 1 943 000	€ 1 925 000
2E	€ 1 736 000	€ 2 479 000	€ 2 392 000	€ 2 384 000[1]

1) Debatable due to floater/tower integration of SWAY concept

For the SWAY concept, viability of lift strategies A, C and E are debatable due to the fact that it is suggested that the concept is designed in such a way that the floater and tower are best integrated at production, leaving strategies where towers are attached to floaters at sea discussable.

Table 25 indicates near-shore turbine installation to be preferable to offshore installation for all concepts, due to the lack of employment of highly expensive offshore crane vessels. As indicated in the table, a lift strategy of two lifts; nacelle and preassembled rotor positioned onto a preassembled floater and tower configuration is preferred for all concepts when evaluating both near-shore and offshore installation, and, accordingly, installation strategy 1D is chosen for all concepts. The WindFloat (Figure 74) and SWAY concepts seem most reasonable to tow, due to their stability.

Figure 74: Towing of the WindFloat pilot project (Maciel 2012)

No obvious installation economies of scale beyond allocations of mobilisation costs are assumed, similar to installation costs for bottom-fixed concepts.

3.3.4 Installation of Mooring System

Installation of mooring systems can be dived into pre-set and concurrent installation. In a pre-set installation, the anchors and mooring lines are pre-laid out and simply hooked up by supply vessels at the time for installation of the floating structure. This allows for a longer weather window, limited interaction with the rest of the installation, but will extend the period of time from installation of the mooring system starts to hook-up of the wind turbines. In a concurrent installation, the anchors and mooring lines are laid out and installed at the same time as the floating structure. It is therefore possible that all activities on site can be performed at the same time, reducing transfers and transports, but will result in many vessels at site during hook-up. (Eriksson & Kullander 2013)

Installation of a mooring system for a large-scale offshore wind farm would require numerous operations due to the number of required anchor installations. Adequately installing several anchors and mooring lines within a limited area would require severe logistical operations prior to installation to ensure a proper installation process. One possibility to improve logistics could be to let mooring lines for several wind turbines be connected to a single, high-capacity anchor, and thus reduce the total number of anchors having to be installed within the farm (Ekrem 2013). However, logistical operations extend beyond the scope of this thesis, and will not be discussed profoundly.

To simplify logistical operations during wind turbine installation, mooring systems are assumed to be installed in a pre-set installation process.

Catenary mooring systems may be installed by only one anchor handling vessel. The shape of the anchor and the low centre of gravity assure an upright landing on seabed and stability during penetration. Suction and friction forces will aggravate the retrieval of the anchor, but the long shank will generate the needed moments to rotate and consequently overcome these forces, as illustrated in Figure 75 (Vryhof Anchors BV 2010a).

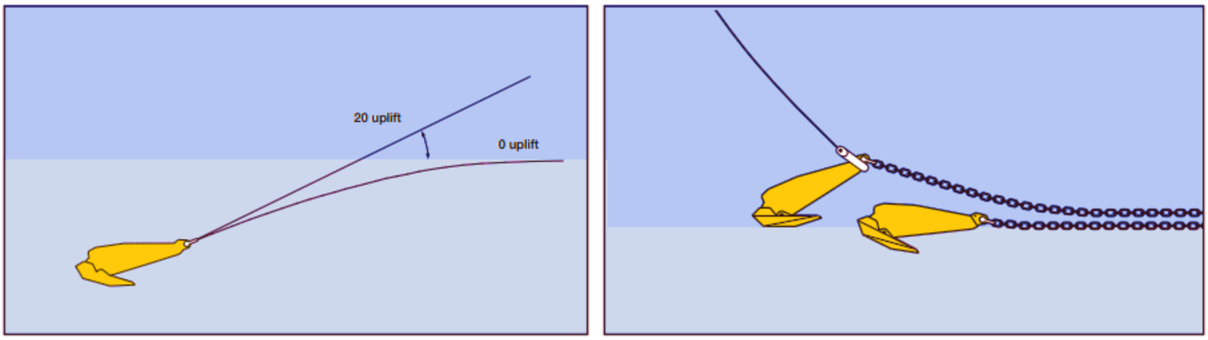


Figure 75: The figure to the left illustrates the DEA in the right loading mode and the figure to the right illustrates the recovery method (Vryhof Anchors BV 2010c)

The taut leg mooring system can be installed by only one anchor handling vessel. To verify the right installed position and drag, the length marks on the forerunner and measurement of the angle between the anchor line and seabed is typically handled by an ROV (Figure 76). To remove the anchor, the front chains or wires are detached and the anchor is pulled opposite to the installation direction with a fraction of the installation load (Vryhof Anchors BV 2010b).

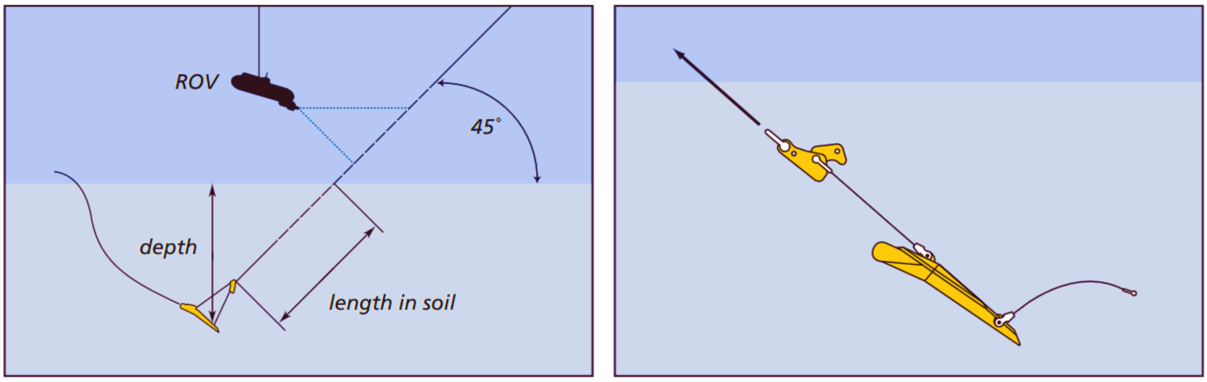


Figure 76: The figure to the left illustrates the verification of the right loading mode and the figure to the right illustrates the recovery method of the Stevmanta VLA (Vryhof Anchors BV 2010b)

The Stevmanta VLA consists of an anchor fluke and an angle adjuster responsible for changing the anchor from installation mode to the preferred loading mode. The loading mode results in an immediate increase of holding capacity of up to 3.5 times the installation load (Vryhof Anchors BV 2010b).

For suction pipe anchor installation (Figure 77), a pump connected to the top of the pipe creates a pressure difference which forces the suction anchor into the seabed. After installation the pump is removed and the anchor is permanently sucked into the seabed. If soil creep resulting in vertical displacement of the anchor is experienced, the suction pile may be repositioned to its original position by operating the suction pile pump. For retrieval of the anchor, the pump is used to counteract the pressure difference to force the suction anchor out of the soil, making the retrieval process opposite of the installation process.

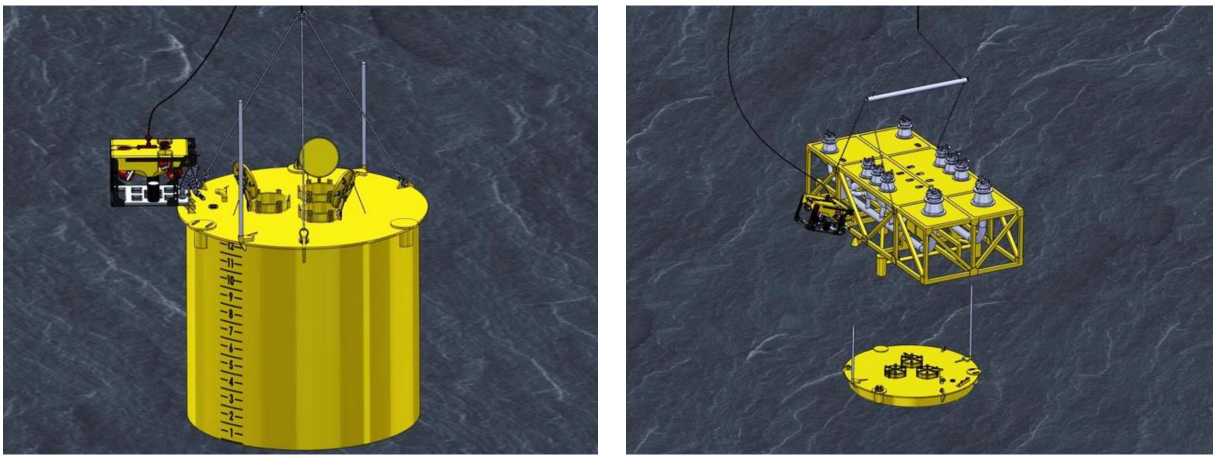


Figure 77: Left (a): Suction Pipe installation with ROV. Right (b): Pump detached from installed SPA (Jelsoft 2008)

The installation process for all mooring systems evaluated for this thesis is assumed to be performed by one large AHTS. For offshore applications, requirements for anchor installation loads to be equal to mooring system design loads exist (Straume 2013), and as of 2013, the largest AHTS delivers a bollard pull of just shy of 400 *tons* (Maritimt Magasin 2011). However, for this thesis we have assumed the indicated day rates for AHTS vessels include capabilities to sufficiently and securely install the discussed mooring systems, either through future capacity developments for AHTS vessels, through a combination of bollard pulls and winch systems or through the use of several, smaller vessels cooperating in installing the anchors. For the taut leg mooring systems, with a holding capacity of approximately 2 000 *tons*, adequate installation loads are realised both through the installation mode setup of the anchor, reducing installation loads to roughly a quarter of holding capacities, and the fact that the excess buoyancy of the TLB concepts may also be utilised to pre-tension the mooring cables (Myhr 2013).

A set of assumptions have been made in order to estimate costs of the mooring system installation operations. Please note that these numbers are assumptions for benchmark wind farms, and that assumption changes with regards to changes in wind farm properties are presented accordingly.

1. Each DEA anchor is assumed to take approximately 8 hours of installation time. This includes all deck rigging (operated simultaneously with transit between anchor sites), launching, lowering of the anchor, seabed penetration and tensioning. VLA anchor installations are assumed to last 9 hours, slightly longer than DEA anchor installations due to the fact that VLA anchor installation modes have to be employed and unemployed. Suction pipe anchors are expected to last 12 hours due to seabed penetration operations and troublesome deck handling of the anchors due to their size (Audibert et al. 2003).
2. Increases in water depth are not expected to impact installation times to a great extent, and accordingly, an increase in installation time of 30 minutes per 100 *m* of additional depth is assumed due to extra time for lowering of the mooring system to the seabed and more troublesome deck handling due to increase in mooring line length (Rem Gambler 2013). These additions are assumed to be equal for all concepts.
3. A free area, approximately 5 *m* in length and as wide as the vessel of the utilised AHTS, has to be reserved for handling of the anchor being installed, leaving the rest of the deck conservatively exploitable for anchor storage (Figure 78) (Siem Offshore 2013). Assuming a 24 *m* wide vessel with a deck space area of approximately 750 m^2, approximately 630 m^2 may be used for anchor and mooring line storage (Maritimt Magasin 2011).

Figure 78: Deck area consumption (Vryhof Anchors BV 2010b)

Based on anchor dimensions, the AHTS is assumed to have following capacities per trip:

- Drag Embedded Anchors are estimated to occupy a deck area of approximately 30 m^2 (Vryhof Anchors BV 2010a). Taking mooring lines into account, the AHTS is assumed to be able to carry a baseline amount of 15 mooring systems, with low and high values at ± 20 %
- Vertical Load Anchors are estimated to occupy a deck area of approximately 30 m^2 (Vryhof Anchors BV 2010a). Taking mooring lines into account, a baseline deck space capacity of 10 anchors is assumed, with low and high values at ± 20 % (greater outer dimensions on mooring lines than for catenary mooring systems)
- Suction Pile Anchors capable of deployment for this thesis are expected to have diameters of approximately 10 *m* (Tjelta 2013), leading to assumed deck capabilities of 6 mooring systems, with low and high values at ± 17 %

4. Deck space capacities are assumed to decrease with one unit per 200 *m* increase in water depth due to the extra amount of mooring lines having to be stored.
5. Installation operations are expected to be done in significant wave heights up to 2.5 *m* (Siem Offshore 2013), giving an approximate operational window of 60 % (assumed operational window for transit: 75 %) (Faltinsen 1990).

Given the mentioned installation times, capacities and day rates, baseline mooring system installation costs for one wind turbine of the different concepts deployed at benchmark wind farm sites are presented in Table 26. Costs include mobilisation costs assigned to each wind turbine.

Table 26: Mooring system installation cost estimates

Concept	**TLB B / TLB X3**	**Hywind**	**WindFloat**	**SWAY**
Anchor type	VLA	DEA	DEA	SPA
Number of anchors per WT	3	3	4	1
Deck capacity	10	15	15	6
Average transit time per anchor	0.06	0.04	0.04	0.10
OW - transit	75 %	75 %	75 %	75 %
Installation time per anchor	0.38	0.33	0.33	0.50
OW - installation	60 %	60 %	60 %	60 %
Installation costs per mooring system	**€ 64 000**	**€ 55 000**	**€ 55 000**	**€ 88 000**
Total mooring installation cost per WT	**€ 192 000**	**€ 167 000**	**€ 222 000**	**€ 88 000**

Installation of vertical mooring systems is indicated to be the most expensive operation per installed system, due to the installation time and deck area consumption, which is high relative to the two other concepts. However, since SWAY only employs one anchor, this concept has the lowest mooring installation costs of the discussed, floating concepts, but when comparing with Table 19, it becomes apparent that the expensive SPA leads to SWAY having the most expensive mooring costs. Catenary mooring systems have the least expensive installation process of the evaluated concepts, leading to the lowest and second lowest total mooring costs for Hywind and WindFloat, respectively, when comparing with Table 19. Economies of scale due to increases in park size are not expected.

3.3.5 Installation of Electrical Infrastructure

This section discusses costs related to installation of export cables, inter-array cables and the offshore substation. These costs are estimated based on generic sources, and not by using vessel rates, personnel utilisation and time consumptions.

Export Cable Installation

In order to reduce risks of cable failure due to impact from trawling, ship anchoring etc., export cables are buried and embedded in the seabed, which makes trench-digging vessels a necessity when installing the cable.

Subsea cable installation costs have proven to severely vary, with prices being in the region of €^{2013} 230 000 - 1 000 000 per *km* of cable route, these variances come from several variables. As mentioned, offshore installation costs depend on vessel costs, which in turn may experience great variance due to supply and demand, fuel costs, utilised combinations of vessel types and numbers etc. Installation process location relative to suppliers influence transfer time consumption, and local site seabed conditions will affect if the cable will benefit from being buried using ploughing, trenching or jetting, the latter an installation method where cables are buried using water jet streams. Subsequently, cable type, number of cables, water depth and weather conditions are other factors that influence which approach is preferred when installing subsea cables. (National Grid 2011)

Cable installation (Figure 79) could be performed relatively quick, with an estimate of 10 *km* per day for the cable installation and somewhat slower burial of the cable. (Notman 2012)

Figure 79: Cable installation by Stemat Spirit at London Array (London Array 2013)

As discussed in section 3.2.4 and Appendix 7, the most reasonable solution for our benchmark farms with regards to capital costs and costs of losses through dissipated ohmic losses and farm downtime is expected to be installation of one single cable, leaving installation costs substantially more reasonable than installation of two cables (National Grid 2011). National Grid (2011) estimates the installation costs of individual, trenched cable to €^{2013} 354 000 - 826 000 per *km* of cable route (National Grid 2011), corresponding to baseline installation costs of €^{2013} 118 million for the benchmark farms. Economies of scale due to increasing offshore distances are not expected.

Inter-array Cable Installation

Inter-array cable installation is expected to be substantially less expensive than export cable installation due to physical properties of the cables, with estimated per *km* costs approximately one third of export cable installation costs (Douglas Westwood 2010). This corresponds to baseline installation costs of approximately €^{2013} 36.4 million for the near 192 *km* of inter-array cable in our benchmark farm. Low and high scenarios are set to ± 10 %.

Offshore substation installation

As presented in Appendix 8, total baseline costs related to installation of substations (Figure 80) for the benchmark wind farms are estimated to approximately €^{2013} 23.8 million for bottom-fixed concepts and €^{2013} 18.6 million for floating concepts, estimated from installation costs associated with jacket-based wind turbines and WindFloat concept wind turbines.

Figure 80: Offshore substation installation by Rambiz at London Array (Mercator Media 2013)

3.4 Operation and Maintenance

Annual costs related to Operation and Maintenance of the wind farm, hereby denoted O&M costs, are key when finding life cycle costs for a wind farm. Annual O&M costs for generic, offshore wind farms have been estimated by several reliable and independent sources, based on bottom-fixed farms. However, these estimates are based on assumptions that the wind farms are positioned severely closer to shore than the benchmark wind farms defined for this thesis, potentially leading to substantially higher reliabilities and lower O&M costs from easier site access and less harsh weather conditions.

For this thesis, O&M cost increments influenced by increasing offshore distances and water depths will be taken into consideration when annual O&M costs are estimated. This will be done using specialised software developed by the Energy Research Centre of the Netherlands, presented in section 3.4.2.

3.4.1 Maintenance

Maintenance actions comprise of several actions intended to maintain the technical state of the wind farm as close to perfect as possible. Actions include removal of damaged parts, exchange of parts, addition of a new part, changes or adjustment of settings, software updates and lubrication or cleaning processes.

Predicting when and where the failures will occur are nearly impossible, but statistics show to some extent that component failure rates follow a particular pattern. The so-called *bathtub curve* is widely used in reliability engineering, and Figure 81 shows this particular form, describing a simplification of expected failure frequency distributions over a component's life time, comprising of three main periods (Ding 2010):

1. Burn-in period: The period where failure rates are high, but decreasing, due to troubles at the beginning stage.
2. Useful life period: The period where failure rates remain constant for a certain time.
3. Wear-out period: The period where failure rates start to increase, indicating aging or wear-out effect.

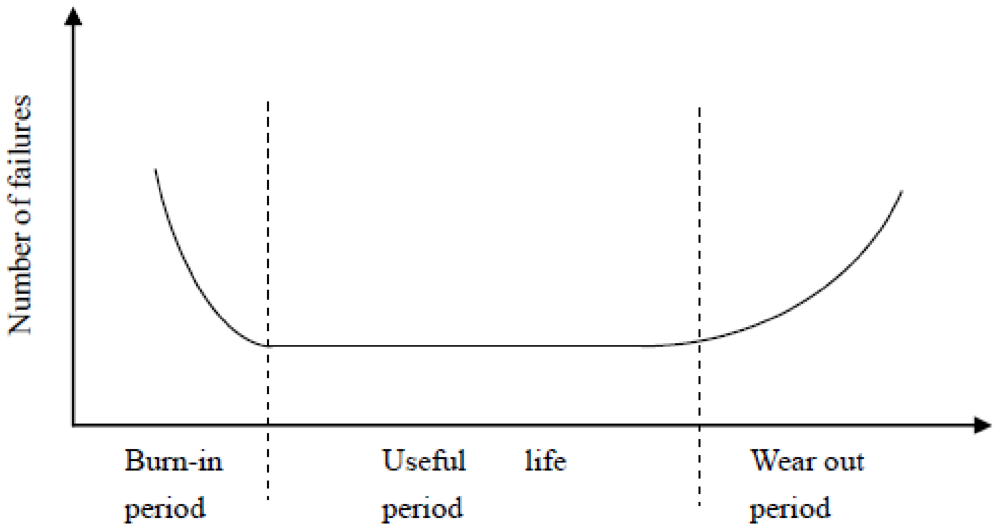


Figure 81: Bathtub curve (Ding 2010).

O&M operation requirements and connected costs are expected to vary according to the bathtub curve over the life time of a real-life wind farm. However, for this thesis, O&M costs are calculated as averaged, annual costs, as the offshore wind industry is not yet mature enough to provide accurate data as to how component-specific bathtub data are expected to vary.

Maintenance Strategy

At a general level, maintenance can be subdivided into preventive and corrective maintenance, or a combination between both. Preventive maintenance is performed in order to prevent a component or system from not fulfilling its design purpose, while corrective maintenance is performed in order to replace or repair a component or system that does not fulfil its design purpose anymore. For this thesis, the following categories for maintenance seems appropriate, as illustrated in Figure 82 (Braam et al. 2007):

- **Calendar based preventive maintenance**: a maintenance method that initiates service and repair of a wind turbine based on fixed time intervals or a fixed number of operating hours, and is independent of the operating status.
- **Condition based preventive maintenance and planned corrective maintenance:** maintenance methods that initiate service and repair of a wind turbine once wear levels have exceeded set limits, and are therefore based on the actual health of the system. It is identified by inspection and/or by other surveillance techniques such as sensors and different types of analyses. Condition based preventive maintenance is foreseen in the design (predicted), but not in advance when the maintenance has to be carried out, while planned corrective maintenance is not foreseen at all (the component does not work properly but fulfils the system demand).
- **Unplanned corrective maintenance:** a maintenance method that initiates service and repair of a wind turbine based on an unexpected failure of a component, where the component does not work and is not able to fulfil its task anymore. It aims at returning the component to functional state, either by repairing or replacing the component.

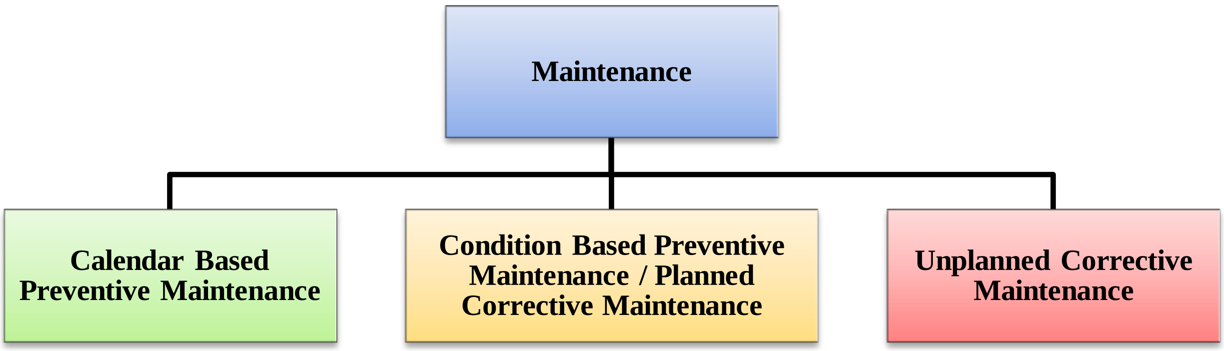


Figure 82: Schematic overview of the maintenance strategy

These categories can be split up further depending on level of detail. In this thesis, we distinguish between minor and major maintenance operations based on the size of components needed for repair, and accordingly, the vessels used. This will be further discussed in section 3.4.2. Figure 83 illustrates the relationship between the different maintenance types and Table 27 summarise the advantages and disadvantages of the different maintenance types.

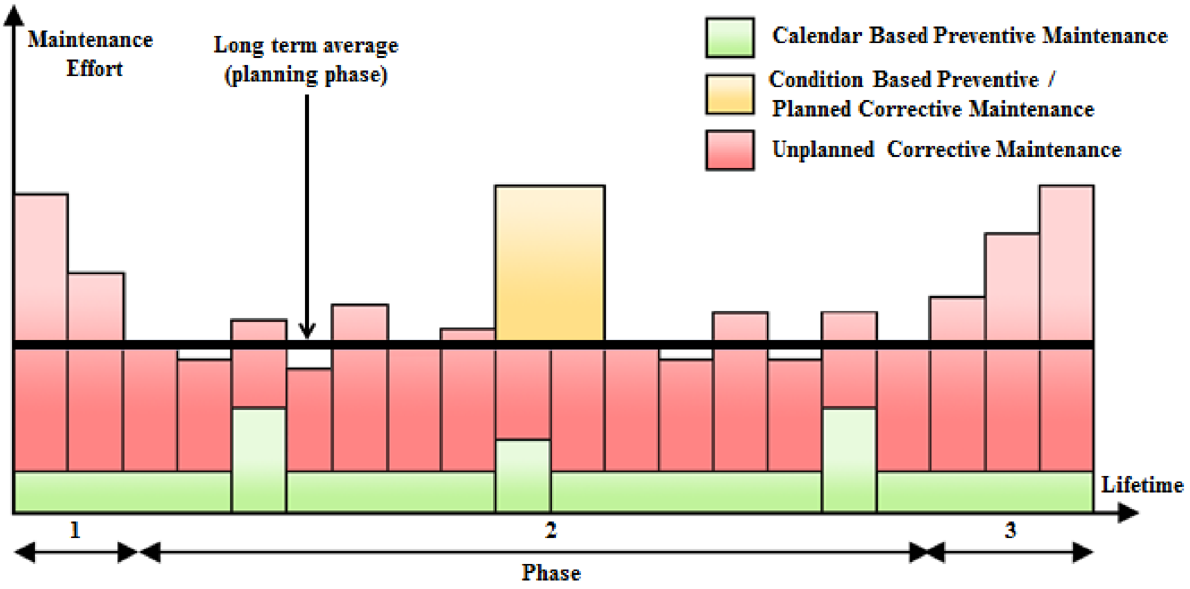


Figure 83: Simplified schematic overview of how the maintenance effort over the lifetime of an offshore wind farm can look like (Braam et al. 2007).

Calendar based maintenance is usually performed one or two times per year, and the costs can be somewhat higher occasionally, e.g. due to oil change in the gearbox. It is more difficult to predict how often unplanned corrective maintenance is performed due to the fact that random failures can happen at all times, but the costs can be somewhat higher than expected due to troubles at the beginning stage. Condition based/planned corrective maintenance is carried out when it is necessary for a major overhaul, due to unexpected wear out of components designed for the lifetime of the project (e.g. replacement of gearboxes or pitch drives). When this type of maintenance has to be carried out during lifetime of the project, it will generally be planned, but does not need to be foreseen initially. (Braam et al. 2007)

Calendar and condition based maintenance can be planned in advance, and therefore the associated costs and downtimes can be determined relatively easy with small uncertainties. For unplanned corrective maintenance the associated costs are much more difficult to predict and are determined with large uncertainties.

(Ding 2010) proposes a combined strategy called opportunistic maintenance. In opportunistic maintenance, the unplanned corrective maintenance performed on failed components can be combined with preventive maintenance carried out on other components. This should be a considerable strategy because there are multiple turbines in the wind farm and the turbine has multiple components. Furthermore, when a down time opportunity has been created by the failed component, the maintenance team may perform preventive maintenance on other components the same time and save substantial cost compared to separate maintenance. (Ding 2010)

From an economic perspective, we can therefore assume it is wise to carry out preventive maintenance on other components when a bigger maintenance operation is performed on a wind turbine.

Table 27: Advantages and disadvantages of the different maintenance types (Ding 2010)

Maintenance type	Advantages	Disadvantages
Calendar Based Preventive Maintenance	- Easy logistics. - Shorter downtime and higher availability. - Maintenance activities can be well scheduled.	- Components won't be used for a maximum lifetime. - Cumulative fixed cost is higher compared to corrective maintenance due to more frequent set out.
Condition Based Preventive Maintenance / Planned Corrective Maintenance	- Components will be used the most efficiently. - Downtime is low and availability is high. - Easy logistics due to a failure can be predicted in time and well scheduled	- High investment and effort on reliable monitoring system. - Not a mature application in wind industry. - Difficult to identify appropriate condition threshold values.
Unplanned Corrective Maintenance	- Components will be used for a maximum lifetime. - Lower investment on monitoring component.	- High risk in catastrophic damage and long down time. - Spare parts and logistics allocation is complicated. - Likely long lead time for repair.

Maintenance Optimisation

To determine the most cost effective maintenance strategy, we need to optimise the maintenance strategy to provide the best balance between direct maintenance costs, e.g. labour, resources and materials costs, and the consequences of not performing maintenance as required, e.g. loss of production and the potential for greater damage on the wind turbines. Carrying out preventive maintenance every year, or even more often, would prevent most of the failure from happening, but may result in more direct costs. In contrast, less frequent maintenance may reduce the costs and elevate the risks. Maintenance will also be affected by the weather and sea state and the wind turbine may be inaccessible for longer periods. Optimising the interaction between these factors may eventually determine the optimum level with the lowest total maintenance costs. (Ding 2010)

Figure 84 shows a simplified optimisation example to determine the optimal balance between direct maintenance costs and the consequences of not performing maintenance as required.

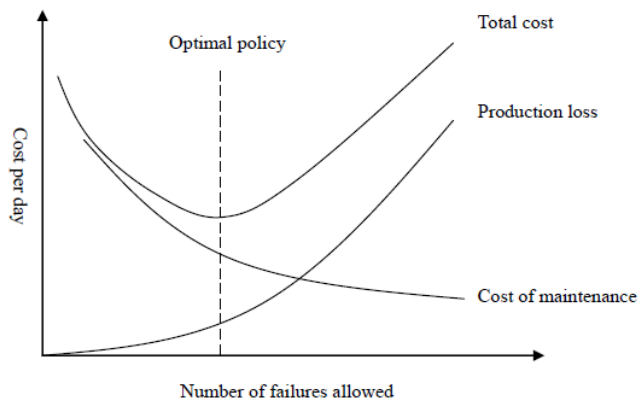


Figure 84: Optimal number of failures allowed (Ding 2010).

In order to focus on the topic of this thesis, we will not develop models for optimising the maintenance strategy. Instead, will we use available data and information and make simplifications to determine the total maintenance costs, discussed in section 3.4.2.

3.4.2 Operation and Maintenance Modelling

To estimate the O&M costs and downtime in the operational phase of the wind farm, we have used the OMCE-Calculator, introduced in section 1.5.4. The OMCE-Calculator contains a default maintenance model, which has been used as a starting point for our analysis. This model does not represent an existing wind farm and the data presented in the model (amongst others failure data, equipment capabilities and costs, repair strategies and wind turbine specifications) are estimates based on previous experiences and engineering judgement by ECN. In reality, such values are expected to be highly site- and time-specific. Accordingly, if the OMCE-Calculator were to be used to predict O&M costs for a real-life wind farm, the calculator would have to be extended with site- and time-specific values. However, the data are considered good estimates for our analysis of a fictitious wind farm positioned at a generic site, but we have still supplemented with own data that is applicable to our analysis.

The OMCE-Calculator has been used to analyse our benchmark wind farm consisting of 100 wind turbines (500 *MW*) that will be in operation for 20 years. Built-in, default meteorological data from the North Sea has been used as grounds for the analysis. The benchmark distance to the farm is set to be 200 *km* from the nearest harbour. The wind farm is connected to the grid via one substation.

For this thesis, it is chosen to distinguish between floating and bottom-fixed farms, as different vessel types for certain maintenance operations may be employed for the two farm categories. Investigated substructure concepts, whether floating or bottom-fixed, are regarded not to differentiate O&M operations and costs further.

When evaluating energy cost changes with changes in certain parameters, we aim to present how changes in variables, such as distance to shore and heavy maintenance vessel types, are assumed to affect the total O&M costs.

Maintenance Operation Overview

The repair costs and efforts of all the different failures that can occur are not equal, meaning that the model can handle that a specific component may fail in various modes. The individual types of faults are modelled based on the default model developed by ECN. The spare parts are divided in different components which have different size, cost, availability and order time. The different repair categories are determined by the maintenance type and the corresponding amount of work, required equipment and time to organise for each maintenance phase. The OMCE-Calculator is considering both preventive (calendar and condition based) and corrective maintenance, as described in section 3.4.1.

Calendar Based Preventive Maintenance

All wind turbines in the wind farm are scheduled to be maintained annually with a maintenance crew of three technicians and an average repair time of 24 hours. This operation is expected to be performed by small specialised maintenance vessels, as shown in Figure 85. In addition, a larger preventive maintenance campaign is carried out every ten years which require double maintenance crew and repair time. Since the wind farm consists of floating structures that is connected to the mooring system, an underwater inspection is required for each wind turbine every year. This preventive maintenance operation requires a diving support vessel with divers and diving equipment and is assumed to take about three hours per turbine. Inspection of the substation is assumed to take 50 hours every year. The preventive maintenance operations are planned in advance and are scheduled for the period of May – September each year, a period with higher expected accessibility due to calmer weather.

Figure 85: Maintenance operation with the FOB SWATH 1 at Greater Gabbard (Odfjell Wind AS 2012)

Condition Based Preventive Maintenance and Planned Corrective Maintenance

Some smaller components in the wind turbine are expected to have a predictable wear pattern and is expected to be replaced the year before a failure is expected to occur. A smaller replacement is expected to take eight hours with a crew of three technicians, while a bigger replacement will require double maintenance crew and repair time. The actual components that follow this type of wear pattern are modelled in the default model in the OMCE-Calculator. Based on the expected time to failure, condition based maintenance is modelled to be performed by next year in the period from May – June.

Unplanned Corrective Maintenance

For simplicity, all operations are expected to be performed on site, although detaching wind turbines from mooring systems prior to towing to shore could be a feasible solution for most of the concepts and will be discussed accordingly. The OMCE-Calculator differentiates between minor and major unplanned maintenance operations. Minor unplanned maintenance operations are assumed to be operations from malfunctions on electrical or other small equipment, which can be carried out without the use of a crane vessel. Major unplanned maintenance operations are assumed to be operations from malfunctions on larger equipment, where repairs have to be completed with assistance from a crane vessel. The different repair operations are assumed to take between four and 48 hours with a crew size between three and six technicians. The repair time and crew size, as well as the different vessels that are required, are depending on the scope of the work that has to be carried out.

The OMCE-Calculator uses generic reliability data that are derived from the results of the Reliawind project (Hendriks & Wilkinson 2011). The failure frequencies per wind turbine component from the Reliawind report includes data of approximately 350 onshore wind turbines and represent the most recent publicly available information on failure rates of large wind turbines. The default model of the OMEC-Calculator uses a wind turbine breakdown based on breakdown of main systems for a 4 *MW* Direct Drive turbine. For our generic 5 *MW* double-fed, asynchronous turbine, we assume breakdown to be similar, and more accurate reliability data for this type of turbine is not available for us at the moment. The main turbine specifications of the analysed wind turbine are described in Table 5 and the associated power curve data is presented in Figure 31. In addition to the wind turbine failures, BOP (Balance of Plant) failures are also taken into account, representing failures in the substation, subsea cables and substructures. These are assumed equal for floating and bottom-fixed concepts.

The failure rates on the subsea cables are based on assumptions that typical failures rates for subsea cable are 0.1 per 100 *km* per year (National Grid 2011). It is unclear if this rate is applicable for both the export cable and the inter-array cable. The export cable may be exposed for trawling and anchoring impacts, while the inter-array cables may be exposed for impact from large installation and maintenance vessels. At the same time, the cables have different voltage and this might lead to different failure behaviour. With little literature on this topic, the failure rate on the export cable and inter-array cables is assumes to be equal, and is set to 0.1 annual failures per 100 *km* of cable for this thesis. For the export cable with the length of 200 *km* for our benchmark farm, the failure rate is assumed to be 0.2 per year. The inter-array cables in our benchmark farm are deployed with five wind turbines per row and a total of 20 rows (Figure 63). The total length of the inter-array cables is approximately 190 *km*, giving a failure rate of approximately 0.19. The average availability for the wind farm if a failure occurs is assumed to be 97 % for the inter-array cables and 0 % for the export cable.

Note that the OMCE-Calculator implements opportunity-based maintenance strategies, and thus seeks to allocate mobilisation costs for external vessels over several turbines and several maintenance operations if simulations indicate this as a possibility.

Accommodation and Port Facilities

Traditionally, work boats have been used to transport technicians to and from site for O&M purposes, which is highly dependent on the weather window. Given the offshore distance from the nearest harbour to the proposed wind farm (> 100 *km*), offshore accommodation seems most feasible, supported by calculations shown in section 3.4.3. Offshore accommodation could be achieved through an on-site living and maintenance platform. (Multiconsult 2012) indicate that a living platform may be a relevant solution for wind farms located more than 20 *km* from shore, while the corresponding distance according to (European Wind Energy Association 2011) is indicated to exceed 50 *km*.

One approach for offshore accommodation could be to combine the accommodation platform with the offshore substation. However, living in close proximity to high voltage equipment may offer numerous issues regarding health and safety. Another approach is to introduce the use of a so-called mother vessel. A mother vessel is a large floating vessel permanently located in the vicinity of the wind farm, offering accommodation for technicians. The size of the mother vessel not only allows the technicians to live close to the farm for extended periods of time, but it is also capable of operating in rougher sea condition and provide sufficient deck and storage space for small components. Additionally, the mother vessel has the ability to deploy multiple smaller maintenance vessels that could transfer the technicians to the wind turbines. In this manner, time available for maintenance can be maximised by significantly reducing transit time for technicians. (European Wind Energy Association 2011)

For this thesis, it is assumed that a mother vessel is deployed and used throughout the operational phase of the wind farm. Further we assume that the mother vessel is capable of storing small components, while larger components are not kept in stock on the mother vessel. A gangway system (Figure 86) from the mother vessel to the wind turbines is expected to be included in the mother vessel, enabling access in severe sea states.

Figure 86: Gangway system for mother vessel (SeaEnergy PLC 2012)

The gangway system may provide safe wind turbine access for technicians in significant wave heights up to 4 m (SeaEnergy PLC 2012). The cost of a mother vessel is discussed in section 2.3.2 and the baseline cost for this analysis is therefore set to be €^{2013} 13.1 million per year. It is assumed that the mother vessel cost includes all crew costs related to operating the vessel, including both marine, medical, hygienical and catering crew (Kjærstad 2013).

In addition to the mother vessel, we assume the need for port facilities. (The Crown Estate 2010) estimates a O&M port to cost €^{2013} 6.3 million per year and (Scottish Enterprise 2011) estimates the cost to be €^{2013} 2.4 million per year. The size of the O&M port will be reduced by using a mother vessel, and we assume the cost for an O&M port to be approximately €^{2013} 2.3 million per year. High and low scenarios are set to ± 11 %. The O&M port is assumed to include (The Crown Estate 2010):

1. Administration facilities and operation rooms, with a control room manned around the clock to monitor the status of the wind turbines and initiate necessary maintenance operations. The operators also need remote land support, such as specific engineering advice, information and support.

2. Lifting equipment to move components from the harbour to the vessels that will carry out a maintenance operation
3. Workshop areas with equipment and tool storage
4. Fuel bunker to store fuel for helicopters and vessels
5. Good connection to the public road network

Personnel

It is expected that the wind farm will both administrative and technical personnel. The technicians will only work in a single shift during daylight periods to ensure a safe environment. Offshore personnel are assumed to work on shifts lasting 12 hours, from 6:00 am to 6:00 pm, and maintenance will only be initiated if technicians can spend a minimum of two hours to the repair onsite. All year long two crews of technicians are employed, who are exchanged from the mother vessel on a 2-week basis. A total number of 60 technicians and two managers for the two crews are assumed to be employed on a fixed contract basis. For condition based maintenance, additional crew is hired for periods when this type of maintenance is performed. This crew is assumed to be paid with a rate of € 70 per hour, which is substantially more than the hour equivalent of the technicians employed on a permanent basis, as these hired crew members are hired from contractors on shorter contracts.

It is also expected that the wind farm needs operational personnel onshore, and a total of six administrative personnel and three technicians are assumed for the benchmark farms.

In a real-life scenario, it could be expected that personnel performing similar tasks may have different labour costs from seniorities, responsibilities etc. Additionally, personnel employed within the same sectors defined for the thesis are expected to perform tasks varying in complexity and costs, e.g. workers employed as onshore administrative personnel are likely to have different wages based on whether they perform managing or logistical operations etc. Accordingly, labour costs for different categories are estimated as averages over the sector. The offshore technician and manager cost estimates are based on UK sector offshore wind energy salaries (Earth Wind & Hire 2013), and adjusted according to assumptions that the relation between direct and indirect labour costs are set equal to that of Norwegian oil and gas industry, with total costs at 140 % of direct salary costs (Statistics Norway 2010). Other sectors are estimated based on these values. Total annual labour costs for the different sectors are presented in Table 28.

Table 28: Fixed annual labour costs for the benchmark farms

Labour	**Employees**	**Fixed annual contract cost**	**Total annual fixed costs**
Offshore O&M technicians	60	€ 67 000	€ 4 020 000
Offshore O&M managers	2	€ 118 000	€ 236 000
Onshore O&M administrative personnel	6	€ 60 000	€ 360 000
Onshore technical personnel	3	$ 50 000	$ 150 000
Total annual labour costs	**82**	**-**	**€ 4 766 000**

Vessel and Equipment Requirements

To maintain the offshore wind farm, the following vessel and equipment are used for the transfer of personnel and spare parts, and for hoisting components:

1. Workboats will be launched from the mother vessel when corrective and preventive maintenance has to be carried out without use of the gangway system, and transports the service technicians to and from the wind turbines. The average travel time is set to one hour. The workboat is also able to transport small parts (up to two *tons*) from the mother vessel to the wind turbines. For this analyse it is assumed to permanently employ two specialised maintenance vessel on a fixed contract, designed to cope with harsh weather conditions, as described in section 2.3.2. Additional vessels are chartered to perform condition based maintenance when required
2. For the replacement of larger components (weights in excess of two *tons*), a larger vessel is chartered on the spot market. For analysing the O&M costs for a bottom-fixed wind farm, a jack-up vessel will be deployed, and for floating wind farms, a floating crane vessel will be evaluated. Large components will not be stored on the mother vessel, and will be specifically ordered and transported to the harbour to be picked up by the crane vessel. For the replacement of the larger components, workboat will assist the operation and transport the technicians
3. To repair or replace power cables in the wind farm, a cable laying vessel is chartered on the spot market. For preventive maintenance of the cables, a diving support ship with a crew of divers or ROVs is used, depending on maintenance depth and operations
4. For underwater inspections and repairs on the substructures or mooring system, a diving support vessel is chartered on the spot market
5. One helicopter is chartered to transport technicians when required
6. Each turbine in the wind farm is equipped with internal cranes, one inside the nacelle and one on the docking platform, capable of lifting small components (up to 2 *tons*)

The fixed annual cost for the specialised maintenance vessel is assumed to have a unit baseline price of €^{2013} 1.9 million per year. Day rates for vessels performing major turbine repairs are volatile and will represent uncertainties to the total estimated O&M costs. These repairs are expected to be performed with vessels of lower specifications than those used for installation purposes (European Wind Energy Association 2011). Since the crane vessel only needs a lifting capacity of about 100 *tons* to carry out a maintenance operation, the day rates for the crane vessel are assumed to be lower compared to the rates discussed in section 2.3.2. For this analysis, the day rates for the jack-up and crane vessels are set to be €^{2013} 196 000 and €^{2013} 300 000, respectively. Day rates are expected to be somewhat lower when WoW, and these are set to 75 % of the mentioned day rates for simulation purposes. Mobilisation is expected to take one month for larger replacement vessels, and mobilisation costs are set equal to four complete day rates.

The remaining cost elements, and other factors relevant for estimating O&M costs not mentioned in this section come from the OMCE-Calculator default model, and will not be presented due to their confidential nature.

3.4.3 Operation and Maintenance Costs

Based on the assumptions made in section 3.4.2, the OMCE-Calculator has been used to estimate the O&M costs and downtime in the operational phase of the wind farm, by performing 50 separate simulations for each of the discussed wind farm qualities. These figures are presented in this section, while costs associated with changes in farm size and offshore distances are presented in Appendix 10.

Table 29 shows the average number of maintenance events per year and indicates that most events are unplanned. Condition-based maintenance numbers are based on one operation performed annually and one operation performed every five years for each wind turbine

Table 29: Number of maintenance events per year averaged over wind farm life cycles

Number of maintenance events per year	**Floating**	**Bottom-fixed**
Unplanned corrective	872	870
Condition-based	4	4
Calendar-based	120	120
Total maintenance events	**996**	**994**

The indicated number of maintenance events for the bottom-fixed wind farm simulation is slightly smaller than the floating wind farm simulation. These differences only come from simulation differences and should be considered equal. The low value for condition-based maintenance comes from the fact that such operations are modelled as a total of 75 different operations (underwater inspections, blade adjustments, yaw gearbox maintenance and foundation maintenance), performed once over the 20 years of lifetime.

Table 30 shows the simulated downtime per year. This downtime is presented as the total downtime over all turbines.

Table 30: Total downtime per year

Total downtime per year	**Floating**	**Bottom-fixed**
Unplanned corrective (*h*)	50 667	54 655
Condition-based (*h*)	55	55
Calendar-based (*h*)	3 360	3 360
Total downtime (*h*)	**54 082**	**58 070**
Availability (time)	**93.8 %**	**93.4 %**
Loss of production per year (*MWh*)	**143 621**	**155 585**

As indicated, unplanned corrective maintenance account for majorities of the wind farm downtime, while condition-based only stand for a minuscule percentage of the wind farm downtime. This is because condition-based maintenance is usually performed in a way where turbines do not have to be shut down. The downtime due to calendar-based maintenance is also expected to be low compared to unplanned corrective maintenance, both because these operations are performed quicker and because shut-down of turbines can be foreseen and planned with calendar-based maintenance.

As for number of incidents, the downtime difference between floating and bottom-fixed farms is expected to come from simulations, and should be considered equal.

Average availabilities are estimated at between 93 % and 94 %, corresponding to assumptions in section 2.2.3 that availabilities are expected slightly lower than those indicated by generic sources for wind farms positioned closer to shore, at 95 % to 98 %. Figure 87 shows average availabilities for the floating benchmark farm on a monthly basis, indicating lower availabilities in summer months than other parts of the year, which at first may seem somewhat contradictory, but these availabilities come from the distribution of calendar-based maintenance periods.

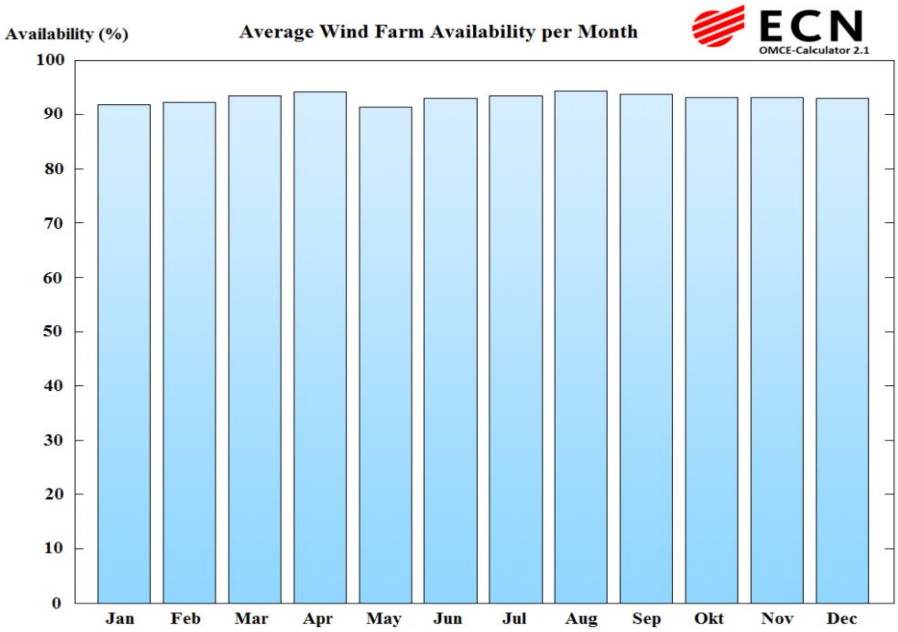


Figure 87: Average wind farm availability per month

Table 31 shows the simulated O&M costs for the investigated benchmark wind farm types.

Table 31: O&M costs per year

Cost of repair per year	Floating	Bottom-fixed
Material costs		
Unplanned corrective	€ 5 372 000	€ 5 381 000
Condition-based	€ 131 000	€ 131 000
Calendar-based	€ 1 600 000	€ 1 600 000
Labour costs		
Unplanned corrective and calendar-based	€ 4 766 000	€ 4 766 000
Condition-based	€ 32 000	€ 32 000
Equipment costs		
Unplanned corrective and calendar-based	€ 42 888 000	€ 35 165 000
Condition-based	€ 1 490 000	€ 1 456 000
Total costs of repair per year	**€ 56 280 000**	**€ 48 532 000**

The table suggests annual O&M costs for floating wind farms are approximately €^{2013} 7.7 million higher than for bottom-fixed parks. This cost difference is almost solely accredited to day rate differences of jack-up vessels and crane vessels, while simulation imperfections may account for a certain variance. As indicated, material costs for both floating and bottom-fixed farms are simulated to be almost equal, and as is condition-based labour costs and condition-based equipment costs. Labour costs besides costs attributed to condition-based labour are fixed costs indicated in section 3.4.2.

Equipment costs are all costs associated with vessel utilisation. Of the *Unplanned corrective and calendar-based* equipment costs, approximately €^{2013} 16.9 million are fixed costs coming from the mother vessel and two specialised maintenance vessels, while the remaining costs come from simulations of employed external vessels.

The total O&M costs are graphically presented in Figure 88. This breakdown is gathered from the benchmark floating wind farm, and shows that equipment costs account for majorities of the total O&M costs of the wind farm at rates of more than three quarters.

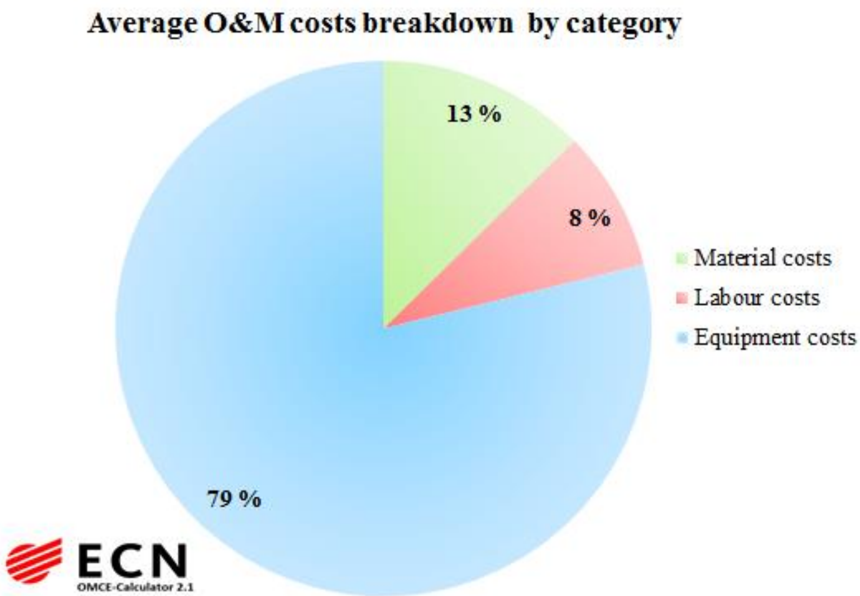


Figure 88: Breakdown of O&M costs

This cost distribution may seem to be somewhat offset from O&M cost breakdowns from other sources, such as (Renewables Advisory Board 2010), where labour is indicated to account for roughly 35 % of annual OPEX, materials for roughly 14 % and *Other costs* for approximately 52 %. However, it must be emphasised that this thesis considers O&M costs from the perspective of a wind farm operator, keeping labour costs associated with vessel crews out of the picture, unlike most generic sources. However, cost breakdowns are supported by both (Renewables Advisory Board 2010) with regards to material cost percentages, and (Douglas Westwood 2010; Scottish Enterprise 2011) with regards to cost percentages associated with wind farm technicians, respectively at 14 % and 8 %.

The equipment cost distributions are further evaluated in Figure 89, where equipment costs for the benchmark floating wind farms are further divided into five categories.

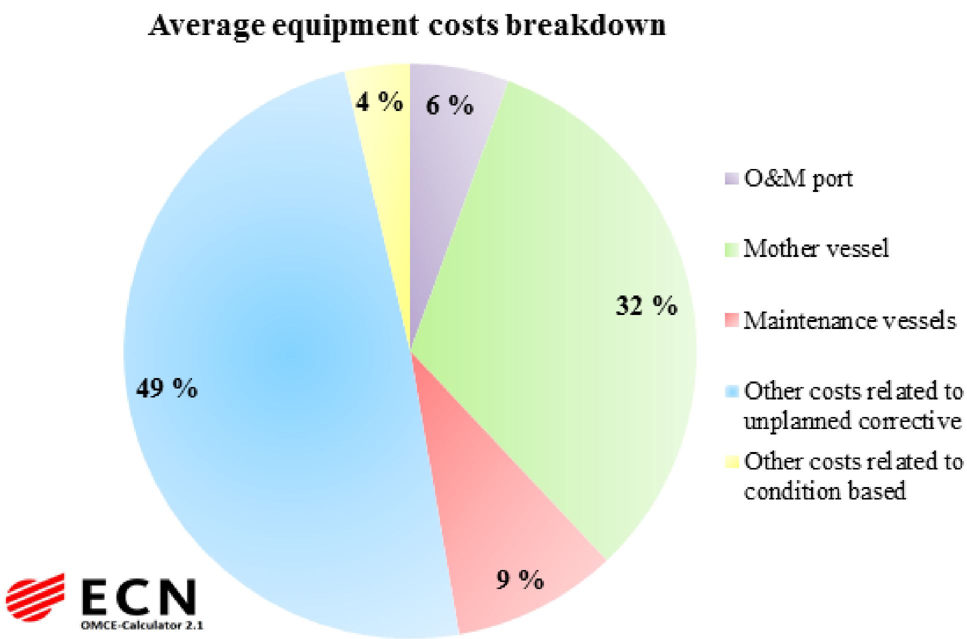


Figure 89: Equipment cost breakdown

As indicated, costs related to rent of external vessels to help with unplanned corrective maintenance (blue) account for nearly half of the annual equipment costs, while costs associated with the mother vessel (green) accounts for the majority of the remaining costs.

The vessel day rates are highly market dependent. The O&M costs for a floating wind farm in Table 31 is based on day rates of €^{2013} 300 000 for the crane vessel. If we assume higher demand of crane vessels, resulting in crane vessel day rates of €^{2013} 531 000 (assumption of section 2.3.2), the total O&M costs are expected to increase approximately 28 %, giving total costs of €^{2013} 72.2 million. Based on the demand and farm size, it may be profitable to buy own vessels, and one feasible scenario could be to integrate the crane vessel and mother vessel. (Multiconsult 2012) indicate acquisition of a purpose built heavy lift vessel for both installation and O&M purposes feasible for farms in excess of 100 units. However, acquisition of larger integrated installation and O&M vessels are not evaluated in this thesis.

It cannot be foreseen whether crane vessels will be available within a realistic period. In case of a bigger unplanned turbine maintenance on floating concepts, where it is necessary to use a crane vessel, another approach could be to use AHTS and tug vessels to tow the complete wind turbines back to shore where a crane barge employs adequate maintenance operations. Annual O&M costs associated with this maintenance strategy, which may be regarded as opposite to the wind turbine installation process, are estimated to approximately €^{2013} 57.6 million through simplified simulations using the OMCE-Calculator, as presented in Appendix 10. The simplified approach could be summarised through stating that per-trip costs related to the entire towing operations are estimated to just shy of €^{2013} 2 million, from cost, time and weather assumptions presented in section 3.3.3 and Appendix 10, and letting the OMCE-Calculator assign these values depending on reliability data. Even though this approach is only assumed to be marginally more expensive than use of crane vessels with day rates of €^{2013} 300 000, operations are assumed to last so long availabilities drop from near 94 % to shy of 92 %. The main reason for these added expenses comes from the fact that with use of AHTS and tug vessels, opportunistic maintenance may not be employed to the same extent as when utilising crane vessels at site. However, the simplified approach used to estimate these costs through the OMCE-Calculator may take into account some clustering of maintenance operations, leading to the estimates to possibly be somewhat liberal. Since the estimates are not further employed, this is disregarded. Other uncertainties come from the fact that costs related to waiting on weather are calculated outside of the model, so the OMCE-Calculator does not deploy its built-in weather data.

As indicated, towing of turbines back to shore does not seem like the most feasible solution for larger maintenance operations, given the assumptions presented when estimating annual O&M costs. However, the approach suggests that if a market situation indicating more expensive crane vessels were to occur, a different strategy for larger maintenance operations could be deployed without affecting O&M costs too severely. With reduced offshore distances, contributions from time related to towing, and accordingly, costs, would be reduced. However, time and costs from detaching and attaching the wind turbines to the mooring systems remain constant with distance, and introductions of towing as the main maintenance strategy is not regarded when evaluating energy cost impacts depending on offshore distance.

In addition to evaluating costs related to towing of wind turbines for larger maintenance, simulations have been run to evaluate costs if no mother vessel is deployed for the benchmark wind farms, and maintenance operations are performed by transporting technicians from shore in specialised maintenance vessels. These calculations, shown in Appendix 10, indicate annual O&M costs of approximately €^{2013} 55.7 million, somewhat less than with use of a mother vessel. However, availabilities drop by nearly three percent, indicating lower electricity production and higher costs of energy. The costs saved by omitting the mother vessel from the O&M cost calculations are almost counteracted by costs assigned to external vessels through waiting for assistance from technicians who are highly dependent on merciful weather. Additionally, the method is associated with long travel times and severe strain on human labour, leading to assumptions that this should not be a recommended maintenance strategy for severe offshore distances.

Operations Phase Insurance

Insurance is essential in the operational phase of an offshore wind project and provides comfort to all potential investors, making it easier to attract capital as well as lowering costs in the long run. The operations phase insurance provides financial protection from physical damage and delays during the operational stage of a project, such as substation outages, design faults and collision risk (PricewaterhouseCoopers 2012). Appendix 11 shows a typical insurance package covering the entire operation period. This package is expected to cost around €^{2013} 15 000 - 20 000 per *MW* per year, typically renegotiated on an annual basis, adding up to €^{2013} 7.5 - 10 million annually for a 500 *MW* offshore wind farm. Adding insurance costs to O&M costs gives annual OPEX costs. (PricewaterhouseCoopers 2012)

3.5 Decommissioning

When the wind turbines have reached the end of their design life, removal and decommissioning of selected components would take place. This includes the wind turbines, floaters and transition pieces, subsea cables and substation. Planning the work and design of any additional equipment that would be required is performed under the development and consenting phase. The practice for decommissioning may vary between countries, but for most countries the plan for this phase must be approved before the offshore installation begins. In this thesis, we assume a similar process for decommissioning of the wind turbines as in (BVG Associates 2012). Decommissioning is assumed to be a reverse assembly process to installation, which will take approximately one year for a generic 500 *MW* wind farm (The Crown Estate 2012). The cables will be cut off at a depth below seabed and most of the cables will not be pulled up. All other infrastructure will be removed and transported back to shore, sorted for recycling and delivered as scrap metal (Figure 90). There may be some residual value attached to the wind farm which could be sold and reused, e.g. reusing substructures by replacing turbines. However, the residual value is not considered for this thesis. Further environmental work and monitoring will be conducted after completing the decommissioning.

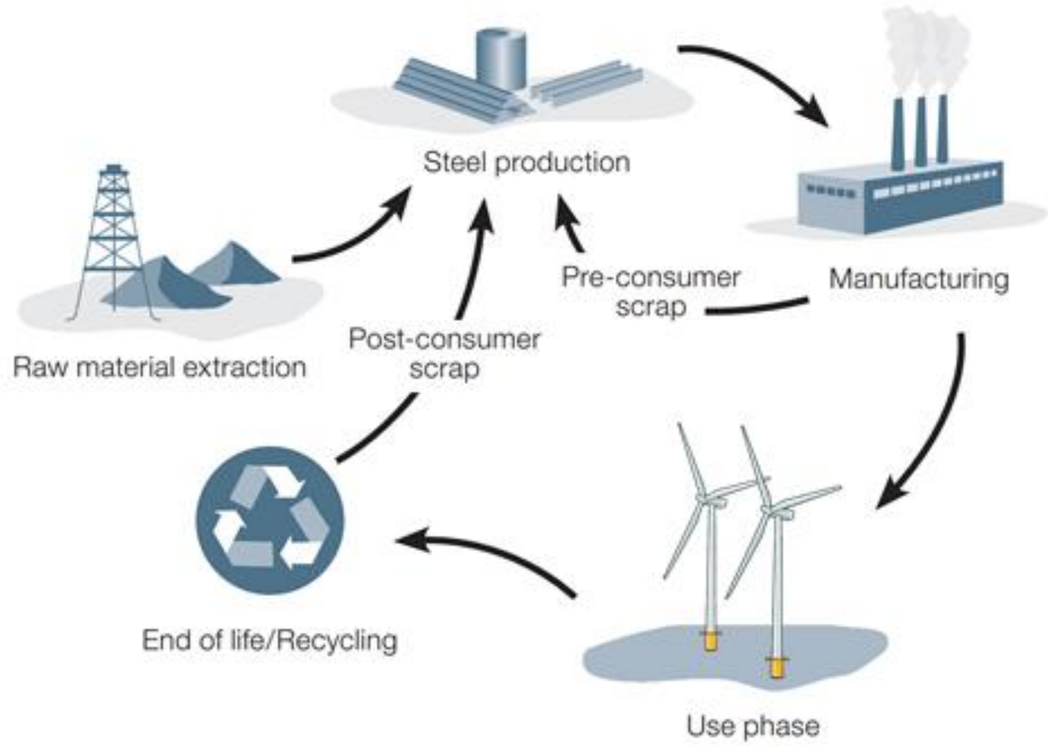


Figure 90: The life cycle of a wind turbine, derived from (The World Steel Association 2012)

When the selected components have arrived to shore the material that will be scrapped have to be cut into suitable length and weights to be transportable by truck and sizes accepted by the steel mills which receive the metal. The cost for cutting tubular steel is determined by the local steel mill and is depending on the cutting method, the complexity of the cut and the steel thickness. The cost for processing the metal and transporting the material from shore to the local steel mill facilities will not be considered in this thesis, since it is depending on many variables and the costs are small relative to the other decommissioning costs.

A great uncertainty exists in terms of the decommissioning costs for offshore wind farms, and even for onshore wind turbines uncertainties exist due to the fact that few wind turbines have approached end of useful lifetime. At the same time, it is assumed that the decommissioning costs for onshore wind turbine are minimal, considering the return value from scrap metal (Multiconsult 2012). For offshore wind turbines, the decommissioning costs will be greater because of the demanding reverse assembly process to installation in open water and the costs related to transporting the remaining infrastructure back to shore.

It is assumed that decommissioning of the wind turbines, grid and electrical equipment requires less focus on accuracy and cautiousness than what is the case in the installation phase, simply because any damage on the components will not matter due to the fact that they are to be recycled or scrapped. Less lenient operation requirements may lead to quicker and cheaper decommissioning. Note that caution with regards to labour safety and vessel integrity are assumed to be adequately maintained throughout the entire life cycle of the wind farm.

(BVG Associates 2012) estimates the average cost of decommissioning of a wind farm to be 65 % of the installation cost. Table 32 shows the assumed decommissioning costs as a percentage of the related installation costs. The removal of the complete wind turbine is assumed to take more time for the bottom-fixed concepts compared to the floating concepts. The removal of the subsea cables will only take 10 % of the time taken to lay, since most of the cables will not be pulled up as discussed earlier. The removal of the substation is assumed to take 90 % of the time taken to install the substation, similar to the decommissioning of the support structure. The same percentage is assumed for removal of mooring system.

Table 32: Decommissioning costs as a percentage of the related installation costs

Description	Percentage of installation costs
Complete wind turbine – Floating	70 %
Complete wind turbine – Bottom-fixed	80 %[1]
Subsea cables	10 %[1]
Substation	90 %
Mooring system	90 %

1) Source: (BVG Associates 2012)

The purpose of determining the decommissioning cost is not to create an exhaustive estimate of all costs likely to be incurred in the decommissioning phase, rather making a simplified estimate over the main drivers involving this phase. Such costs can be estimated but are beyond the scope of this analysis.

Scrap value varies greatly on monthly and yearly basis, depending on economic conditions and so on. Since the scrap price is so volatile, it is difficult to estimate the scrap price 20 or more years in advance. Figure 91 shows the Scrap Price Index for demolition scrap calculated on the basis of the average price in € per *ton* for France, Germany, Italy, Spain and UK.

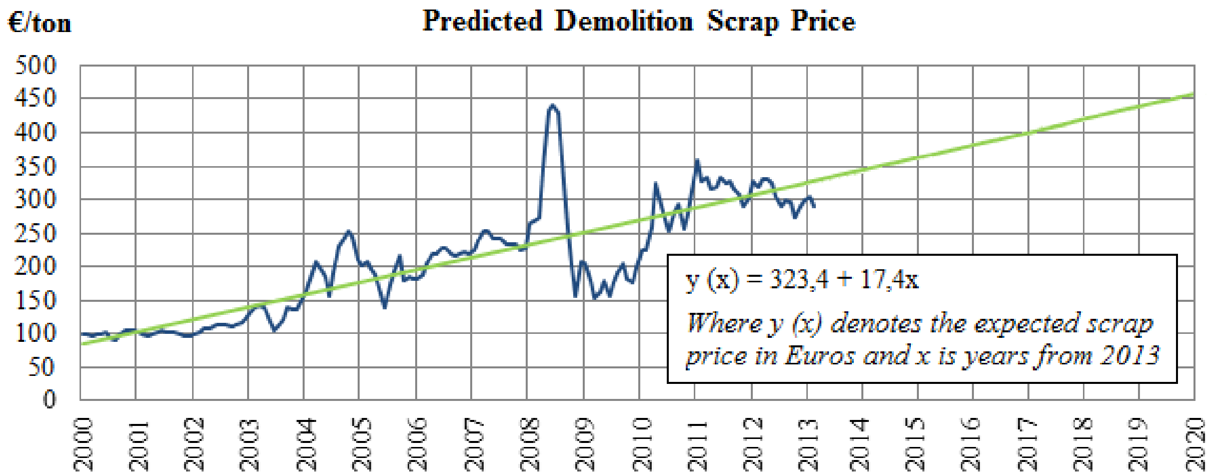


Figure 91: Scrap Price Index - Demolition Scrap (The European Steel Association 2013).

Based on the average scrap price index between 2000 and 2013, the scrap price at time of decommissioning (20 years after commissioning for the benchmark farm) is estimated to be €^{2013} 709 per *ton*. Low and high scenarios are set to ± 10 %.

Scrap steel values of the different concept wind turbines are evaluated from substructure steel consumptions, presented in Table 14 and Table 15, turbine material consumption presented in Table 5 and mooring system discussed in section 3.2.3. The expected decommissioning costs per *MW* for each concept are presented in Table 33 and Table 34.

Table 33: Expected approximate decommissioning costs per MW. All values in €^{2013}

Concept	TLB B	TLB X3	Hywind	WindFloat
Decommissioning costs	€ 205 000	€ 205 000	€ 203 000	€ 193 000
Scrap revenue	€ 133 000	€ 142 000	€ 311 000	€ 424 000
Total DECEX	**€ 72 000**	**€ 63 000**	**- € 108 000**	**- € 231 000**

Table 34: Expected approximate decommissioning costs per MW. All values in €^{2013}

Concept	SWAY	Monopile	Jacket
Decommissioning costs	€ 170 000	€ 302 000	€ 368 000
Scrap revenue	€ 193 000	€ 238 000	€ 125 000
Total DECEX	**- € 23 000**	**€ 64 000**	**€ 244 000**

Of the evaluated concepts, the decommissioning cost is expected to be highest for bottom-fixed jacket concepts, as the installation cost, and thus decommissioning cost is highest for this concept. Additionally, the jacket structure relies on relatively low material consumption, giving low return from scrap steel. Due to relatively inexpensive installation costs for floating concepts, these are also expected to be associated with low decommissioning costs. SWAY and WindFloat provide the lowest values due to relatively inexpensive wind turbine and mooring system installation operations. Additionally, the three heaviest floating concepts, Hywind, WindFloat and SWAY, are expected to gain so much from scrap steel that the scrap value exceeds the modest decommissioning costs, resulting in negative DECEX values.

4. LEVELISED COST OF ENERGY ANALYSES

The purpose of this section is to summarise and discuss findings from chapter 3, by presenting baseline capital expenditures prior to and during installation of the benchmark wind farms, operational expenditures during the operation phase of the different wind farms' life time, and decommissioning expenditures for the final life cycle stages. Energy production estimates are used as bases for finding benchmark site levelised costs of energy for the different concepts, both through baseline scenarios and high and low cost scenarios affected by capacity factors and availabilities.

4.1 Capital Expenditures

This section summarises all baseline capital expenditures (CAPEX) found in chapter 3 of the thesis, presented in Table 35 and Table 36.

Table 35: Concept CAPEX costs per MW. All values in €^{2013}

Descriptions	TLB B	TLB X3	Hywind	WindFloat
Development and consenting	€ 208 000	€ 208 000	€ 208 000	€ 208 000
Construction phase insurance	€ 50 000	€ 50 000	€ 50 000	€ 50 000
Turbine costs (excl. tower)	€ 1 281 000	€ 1 281 000	€ 1 281 000	€ 1 281 000
Production costs (incl. tower)	€ 326 000	€ 371 000	€ 888 000	€ 1 640 000
Mooring costs (incl. inst.)	€ 421 000	€ 421 000	€ 126 000	€ 170 000
Grid costs (incl. inst.)	€ 1 097 000	€ 1 097 000	€ 1 097 000	€ 1 097 000
Installation of wind turbine	€ 154 000	€ 154 000	€ 157 000	€ 129 000
Per *MW* CAPEX (€^{2013})	**€ 3 538 000**	**€ 3 582 000**	**€ 3 807 000**	**€ 4 574 000**
Benchmark farm CAPEX	***M*€ 1 769**	***M*€ 1 791**	***M*€ 1 903**	***M*€ 2 288**

Table 36: Concept CAPEX costs per MW. All values in €^{2013}

Descriptions	SWAY	Monopile	Jacket
Development and consenting	€ 208 000	€ 208 000	€ 208 000
Construction phase insurance	€ 50 000	€ 50 000	€ 50 000
Turbine costs (excl. tower)	€ 1 281 000	€ 1 281 000	€ 1 281 000
Production costs (incl. tower)	€ 550 000	€ 612 000	€ 768 000
Mooring costs (incl. inst.)	€ 343 000	-	-
Grid costs (incl. inst.)	€ 1 097 000	€ 1 070 000	€ 1 070 000
Installation of wind turbine	€ 131 000	€ 300 000	€ 383 000
Per *MW* CAPEX (€^{2013})	**€ 3 661 000**	**€ 3 521 000**	**€ 3 759 000**
Benchmark farm CAPEX	***M*€ 1 830**	***M*€ 1 760**	***M*€ 1 880**

The table indicates that the monopile wind farm is expected to have the lowest CAPEX values at benchmark sites, with the TLB concepts following close behind. Hywind and WindFloat are the concepts with the highest CAPEX values associated with construction of benchmark wind farms. As indicated in the table, the single most dominant CAPEX cost for concept benchmark wind farms are costs related to acquisition of the turbines, with one exception. Because of the tremendous substructure weight and assumed complexity, WindFloat is expected to have production costs for the substructure as the dominating CAPEX cost. A graphical breakdown of baseline CAPEX costs for benchmark sites is presented in Figure 92.

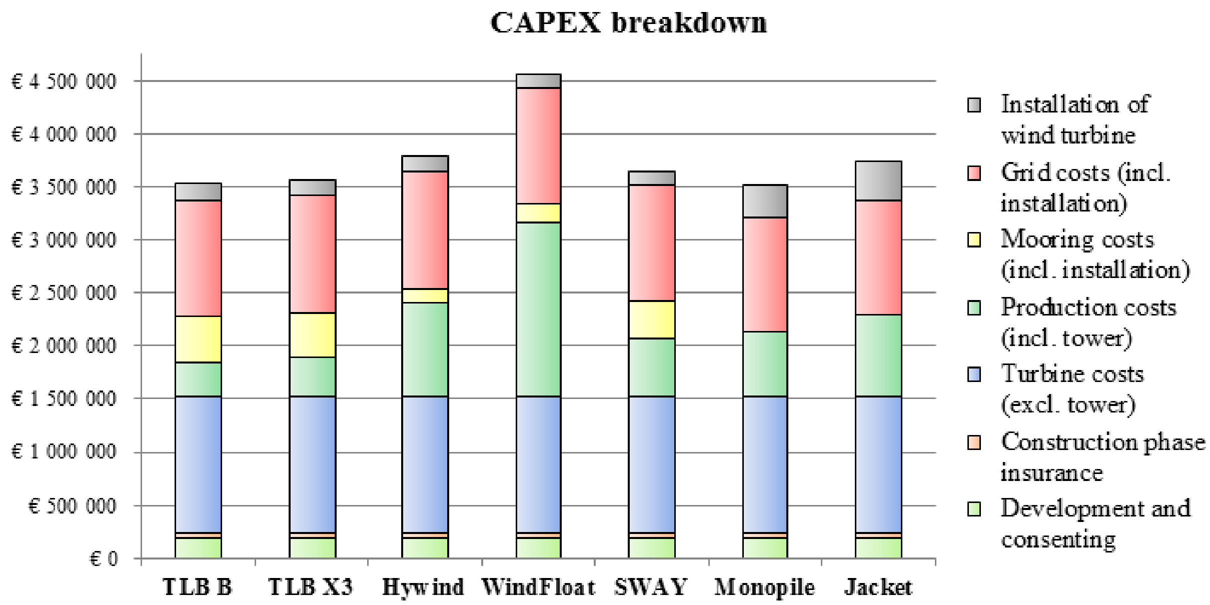


Figure 92: CAPEX per MW breakdown

The graphical breakdown illuminates the key differences between evaluated concepts, based on the set assumptions. The TLB concepts are expected to have the lowest production costs, indicating a severe advantage over the rival floating concepts closest to commercial realisation. However, mooring costs for the TLB and SWAY concepts are considerable when being compared to Hywind and WindFloat. Note that mooring costs are expected to be highly dependent on site seabed conditions, and that mooring system CAPEX costs could be both higher and lower with different benthic conditions.

Grid connection costs are expected to be a dominant contribution to total CAPEX values for all concepts. All comparable concepts are assigned equal grid connection costs.

The bottom-fixed concept CAPEX costs do not include mooring costs, but high production and installation costs almost or completely counteracts these effects for monopile and jacket concepts. Altogether, all concepts except WindFloat lie within a CAPEX margin of approximately 8 %.

The total CAPEX costs for the benchmark wind farms lie close to equivalent CAPEX costs indicated by generic sources, ranging from approximately €^{2013} 1 800 - 1 900 million (Douglas Westwood 2010; Scottish Enterprise 2011; The Crown Estate 2010). These indications are predominantly based on bottom-fixed wind turbines positioned closer to shore than our benchmark farms, leading to assumptions that especially comparable bottom-fixed concepts should have CAPEX costs somewhat higher than the source estimates. However, our estimates do not include contingency additions, leading to assumptions that our CAPEX estimates seem reasonable.

4.2 Operational Expenditures

This section summarises all operational expenditures (OPEX) found through O&M costs and operation phase insurance costs presented in section 3.4.3 of the thesis. OPEX costs are presented in Table 37.

Table 37: OPEX per MW

Descriptions	**Floating concepts**	**Bottom-fixed concepts**
Annual operation & maintenance costs	€ 113 000	€ 97 000
Annual operation phase insurance costs	€ 18 000	k€ 18 000
Per *MW* OPEX (€^{2013}/annum)	**€ 131 000**	**k€ 115 000**
Benchmark farm OPEX	***M€* 65**	***M€* 57**

As indicated in the table, benchmark OPEX costs for floating concepts are assumed to be approximately 14 % higher than those for bottom-fixed concepts. These cost differences are attributed to vessel costs related to unplanned maintenance, as jack-up vessels employed for bottom-fixed wind farms have day rates of approximately two thirds of their floating equivalents.

The estimated O&M costs for bottom-fixed and floating farms are somewhat higher than those indicated by generic sources, with rough estimates between €^{2013} 45 - 50 million per annum (Douglas Westwood 2010; Scottish Enterprise 2011; The Crown Estate 2010). This difference is likely to come from increased offshore distance relative to sources, affecting both O&M costs through increased transportation costs and introduction of a mother vessel, as well as increased maintenance efforts on export cables.

4.3 Decommissioning Expenditures

Costs related to decommissioning of the concept wind farms, DECEX costs, are presented in section 3.5 and summarised in Table 38 and Table 39.

Table 38: DECEX per MW. All values in €^{2013}

Concept	**TLB B**	**TLB X3**	**Hywind**	**WindFloat**
Decommissioning costs	€ 207 000	€ 207 000	€ 205 000	€ 195 000
Scrap revenue	€ 133 000	€ 142 000	€ 311 000	€ 424 000
Per *MW* DECEX (€^{2013})	**€ 74 000**	**€ 65 000**	**- € 106 000**	**- € 229 000**
Benchmark farm DECEX	***M€* 37**	***M€* 33**	**- *M€* 53**	**- *M€* 115**

Table 39: DECEX per MW. All values in €^{2013}

Concept	**SWAY**	**Monopile**	**Jacket**
Decommissioning costs	€ 172 000	€ 304 000	€ 371 000
Scrap revenue	€ 193 000	€ 238 000	€ 125 000
Per *MW* DECEX (€^{2013})	**- € 20 000**	**€ 67 000**	**€ 246 000**
Benchmark farm DECEX	**- *M€* 10**	***M€* 33**	***M€* 123**

The decommissioning costs are expected to be highest for bottom-fixed jacket concepts, because of the set relation between decommissioning and installation costs, as bottom-fixed concepts are expected to have higher installation costs, summarised in section 4.1. Due to low installation costs, floating concepts are expected to have low decommissioning costs, and by adding scrap steel revenue, the three heaviest concepts (WindFloat, Hywind and SWAY) are expected to have negative total DECEX values.

4.4 Levelised Cost of Energy Results

Here, levelised costs of energy for the evaluated concepts are presented, based on distributed and discounted baseline costs relative to discounted baseline net generation. Additionally, concept LCOE ranges are presented through finding the equivalent values for all low and high case scenarios for costs.

LCOE results for this thesis are based on assumptions that FID is set to 2013 and WCD is assumed to be five years later, in 2018. The different CAPEX costs are distributed over the six-year period from FID to one year past WCD according to when they are assumed to occur, and these assumptions are based on (BVG Associates 2012) and (Howard 2012). Discount factors are based on weighted average costs of capital of 8.2 %, as introduced in section 1.5.3.

Table 40: Distribution of CAPEX costs

Phasing (years)	**-4**	**-3**	**-2**	**-1**	**0**	**1**
Discount rate factor	**1**	**0.961**	**0.889**	**0.821**	**0.759**	**0.701**
Development and consenting[1]	56 %	10 %	11 %	11 %	12 %	1 %
Construction phase insurance[2]	0 %	25 %	25 %	25 %	25 %	0 %
Turbine costs (ex. tower) [2]	0 %	0 %	19 %	39 %	42 %	0 %
Production costs (incl. tower)	0 %	0 %	19 %	39 %	42 %	0 %
Mooring costs (incl. installation)	0 %	0 %	0 %	40 %	60 %	0 %
Grid costs (incl. installation)	0 %	20 %	75 %	5 %	0 %	0 %
Installation of wind turbine[2]	0 %	0 %	0 %	36 %	64 %	0 %

1) Source: (BVG Associates 2012)
2) Source: (Howard 2012)

O&M costs are assumed to be distributed by 100 % of annual costs assigned annually from the year after WCD (Year 1 according to Table 40) and throughout the lifetime of the benchmark wind farm. DECEX costs are assumed to be distributed by 100 % at the year of decommissioning, 21 years past WCD for the benchmark wind farms.

LCOE values are computed using a MS Excel LCOE model based on (Howard 2012). Per *MW* CAPEX, OPEX and DECEX values, both baseline, low cases and high cases, are implemented in the model and distributed according to presented distribution values, i.e. through values presented in Table 40. Based on presented discount rates and energy production range estimates shown in section 2.2.3 and Digital Appendix 1, LCOE ranges for all concepts are calculated.

These LCOE ranges are presented in Figure 93, with baseline concept LCOE breakdowns presented in Figure 94.

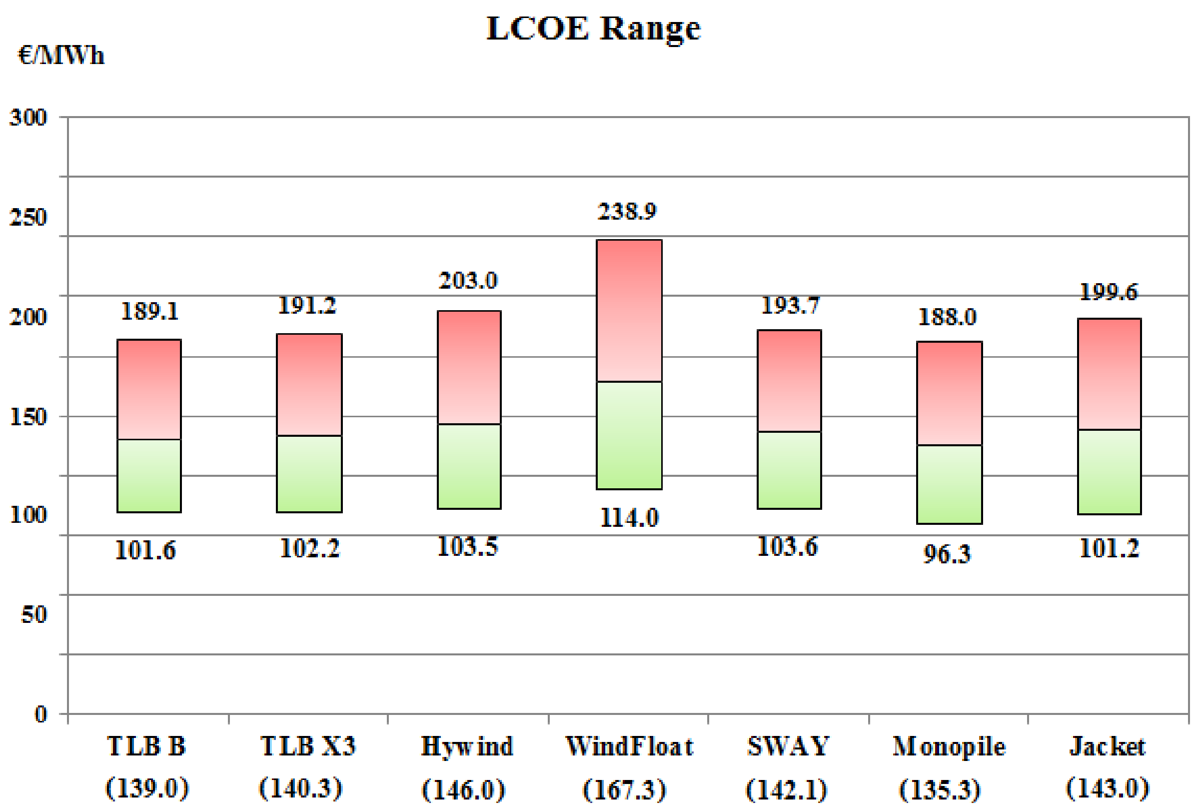


Figure 93: Concept levelised costs of energy at benchmark sites

The figures indicate lowest baseline LCOEs at benchmark sites for the monopile-based bottom-fixed wind turbines at €^{2013} 135.3 per *MWh*. The TLB B concept is expected to come in second, with baseline LCOE at €^{2013} 139.0 per *MWh*, approximately 2.7 % higher than monopiles. The TLB X3 concept is expected to have slightly higher LCOE due to added material consumption and production costs relative to TLB B. Jacket structures and SWAY are indicated with LCOEs of approximately €^{2013} 142.0 per *MWh*, while the Hywind and WindFloat concepts are indicated somewhat higher at €^{2013} 146.0 and €^{2013} 167.3 per *MWh*, respectively.

Based on expected Northern European electricity price estimates of approximately €^{2013} 40 - 50 (European Commission 2012b), it seems offshore wind projects would have to rely on cost reductions through market and technology developments, political efforts and incentives, or a combination of these in order to obtain economic viability. European support levels for offshore wind energy are highly dependent on country, ranging from close to nothing to near €^{2013} 150 per *MWh*, more thoroughly presented in Appendix 3. Accordingly, economic viability of the concepts are expected to vary with project location, but it seems the lower cost concepts at benchmark conditions may even presently be nearly or completely feasible from an economic point of view within thesis limits. Examples include, but are not limited to, Germany and the Netherlands, where average support levels for offshore wind energy presently seem to be between €^{2013} 100 - 150 per *MWh*, depending on offshore wind energy project qualities.

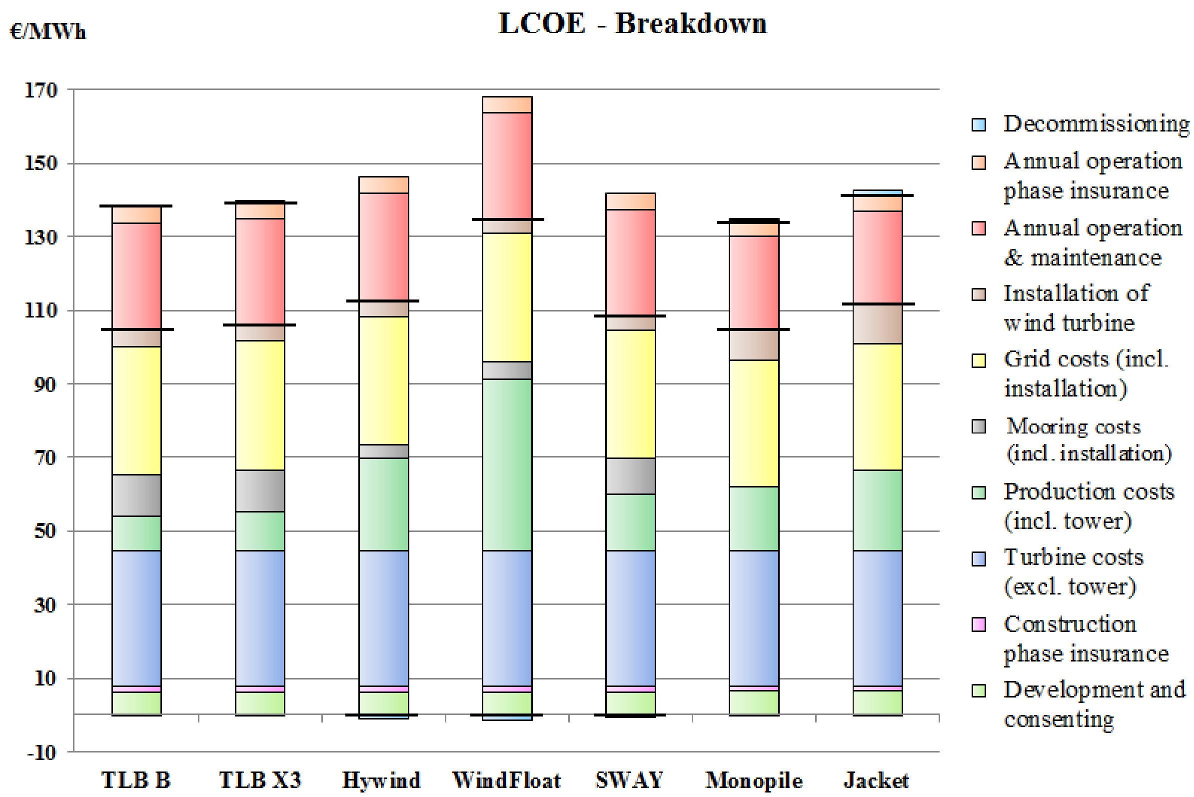


Figure 94: Baseline LCOE distribution breakdown. Black lines indicate borders between CAPEX, OPEX and DECEX

As indicated in the figure, the LCOE values are dominated by CAPEX costs, denoted by all breakdown values between the X axis and the first black line occurring near €^{2013}*/MWh* 100 - 130, depending on concept, on Figure 94. These come early in the life cycle of the wind farms, and, accordingly, are not discounted to the same degree as costs occurring at a later stage (Figure 95). The main drivers to the energy costs for all concepts beside WindFloat are those from turbine acquisition and grid connection, which is expected, as the included components involve most of the technology utilised for energy production. However, for the Hywind and WindFloat concepts, production costs severely attribute to concept LCOE. Additionally, OPEX costs, which are indicated above mentioned black line, attribute to roughly between one fifth and one quarter of the total LCOE. DECEX costs are relatively small, and in some instances negative. Since these occur at a late stage, they are discounted to the level where they almost have no impact on the total concept LCOE.

The TLB concepts and SWAY are expected to have the highest mooring cost contributions, while the bottom-fixed concepts are expected to have highest wind turbine installation cost contributions to LCOE.

Total cost distributions over the life cycle of the TLB B concept at benchmark farm site are shown in Figure 95. As indicated, the majority of the LCOE costs occur prior to WCD, and in relation, DECEX costs are regarded minuscule.

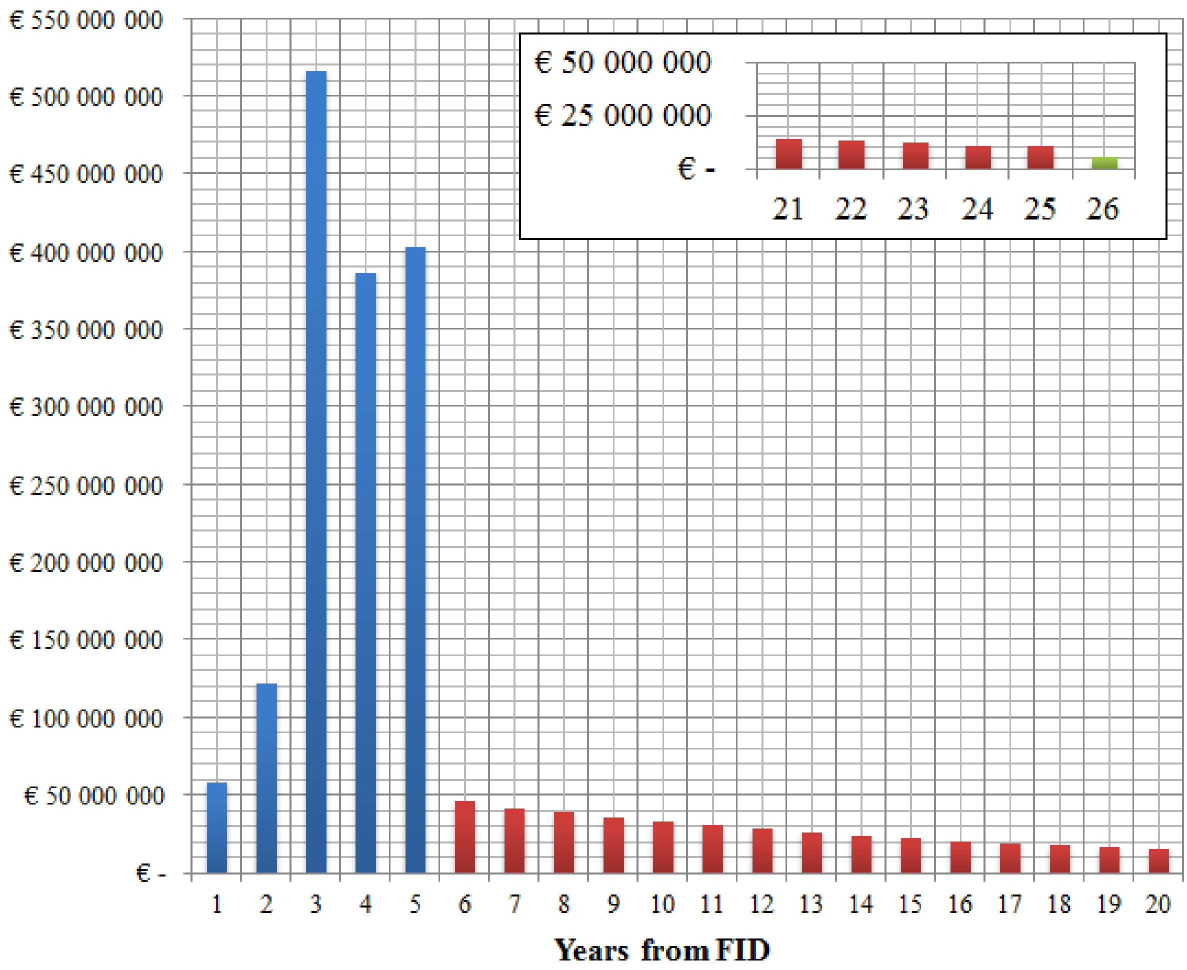


Figure 95: Life cycle LCOE distribution TLB B (Blue indicates CAPEX contributions to LCOE, while red and green indicate OPEX and DECEX, respectively)

4.4.1 Levelised Cost of Energy Model Verification

The MS Excel LCOE model's ability to produce plausible results has been tested by comparing life cycle costs and LCOE figures on current project trends from The Crown Estate (Howard 2012; The Crown Estate 2012) with LCOE model results coming from input of variables as close to reference sources as possible, to compare results on as level grounds as possible. From (Howard 2012), the so-called *Case A*, comprising of a 500 MW monopile farm positioned 40 *km* from port is used as a reference basis due to similarities with certain site qualities, such as water depth and foundation structure. Altered conditions include:

1. Setting the offshore distance to 40 *km*
2. Setting annual net full load hours to 3 482
3. Setting discount rates equivalent to (Howard 2012) at approximately 9.2 %
4. Adding a 10 % contingency to CAPEX costs

Given the thesis assumptions and change of distance dependant parameters, net load factors, discount rates and contingencies, the MS Excel LCOE model indicates an LCOE value of approximately €^{2013} 157.8 per *MWh*, while (Howard 2012) indicates equivalents of €^{2013} 162 per *MWh*, approximately 2.6 % more than what is indicated by the MS Excel LCOE model.

However, the (Howard 2012) data are different from thesis data in some aspects. Firstly, the thesis implements a somewhat smaller tower, and disregards costs associated with component transport. Secondly, installation processes are assumed to be performed continuously, not periodically, which may add to mobilisation costs. Finally, (Howard 2012) does not implement scrap steel revenues for DECEX costs, although the discounting of such values are expected to be so severe this fact has minuscule impacts. Additionally, certain areas of the input values are not directly comparable because of certain assumptions, e.g. AC grid connections are preferred for (Howard 2012; The Crown Estate 2012). However, the comparisons seem to indicate the MS Excel LCOE model (Digital Appendix 1) is able to produce plausible LCOE results.

LCOE results are also supported by (Delay & Jennings 2008), suggesting LCOE values for space-frame structures at water depths and offshore distances comparable to thesis sites roughly 3 % higher than baseline LCOE for jacket structures.

4.4.2 Onshore References

To put estimated levelised costs of energy for offshore wind concepts into perspective, onshore equivalents, i.e. LCOE approximations for land-based large-scale wind farms, are briefly presented.

Figure 96 shows the levelised cost of energy trend for onshore wind in the period from 1980 to 2009. The data represents historical evaluations from four different sources, including analyses from Lawrence Berkley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL), Danish Energy Agency (DEA) and published estimates from Lemming et al, all presented in (Hand et al. 2012), and Bloomberg New Energy Finance (Liebreich 2013).

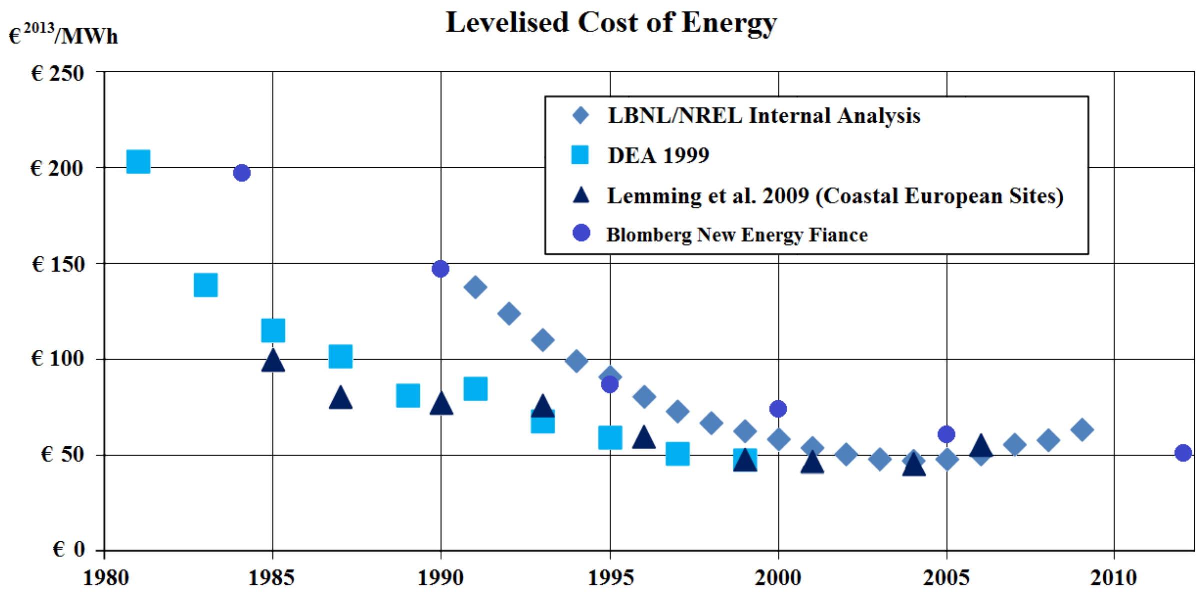


Figure 96: Onshore LCOE trends from 1980 to 2012, derived from (Hand et al. 2012; Liebreich 2013)

From the early 1980s to the early 2000s, the LCOE values have been reduced significantly due to falling costs, enhanced performance and technological developments. After periods with decreasing costs, the trend shows increasing cost from 2004 to 2009.This increase in capital costs has been largely tied to increases for the to the costs related to the turbine. The turbine costs have been driven by increases in materials prices, energy prices, labour costs, and manufacturer profitability, among others.

The figure indicates that present LCOE values for onshore wind farms are close to €^{2013} 50 per *MWh*, nearly one third of the offshore LCOE values presented in Figure 93.

A number of reasons lie behind onshore costs to be significantly less than less mature offshore equivalents. One key aspect is that for onshore applications, turbines do not have to withstand harsh offshore environments, leading to less expensive turbines. Substructures are not to the same extent exposed to environmental loads, while distances and environments may reduce grid connection costs. Additionally, costs related to installation and O&M are reduced relative to offshore equivalents are expected to be severely lower due to easier site access (Figure 97), although these are costs expected to vary with site terrains.

However, dependency of land areas and visual and acoustic pollution, as well as lower wind energy potential onshore indicates further development of offshore wind energy industry.

Figure 97: Installation of onshore wind turbine (Sarens Group 2013)

5. SENSITIVITY ANALYSES

In the sensitivity analysis section, we will evaluate how levelised costs of energy for the different concepts are affected by changes in key cost drivers, while other factors are held constant at baseline levels for benchmark sites. Despite being the main focus of the thesis, the sole purpose of this section is not only to evaluate how changes in cost drivers affect the concepts differently, but also to explore how changes in cost drivers that have similar effects on all concepts affect the levelised costs of energy for a generic offshore wind farm.

Evaluated key cost drivers include:

1. Farm sizes
2. Offshore distances
3. Water depths
4. Wind farm life spans
5. Total number of export cables
6. Steel prices
7. Vessel rates
8. Turbine costs
9. Load factors
10. Discount rates
11. Contingencies
12. Other cost reduction potentials

5.1 Farm Size

This section is intended to evaluate the effects on concept LCOE of gradual increase in farm size, from benchmark farms consisting of 100 turbines to farms consisting of 1 000 turbines. The following costs are assumed to change with increasing farm sizes:

1. Development and consenting costs: linear increase with 50 % of the benchmark baseline costs per added 100 turbines in farm
2. Insurances: proportional increase
3. Turbine- and substructure production costs: proportional increase
4. Installation costs (ex. mobilisation) : proportional increase
5. Mooring costs (ex. mobilisation): proportional increase
6. Grid costs: proportional increase for acquisition of inter-array cables. Substations and export cables changed according to increased farm capacity, costs relevant to these increases are presented in section 3.2.4, section 3.3.5, Appendix 7, Appendix 8 and Digital Appendix 1
7. O&M costs changed according to lower administration costs and economies of scale for utilisation of vessels. Mother vessel costs are assumed not directly proportional to size, as discussed in Appendix 10

Concept LCOE values with regards to changes in farm size are presented in Figure 98.

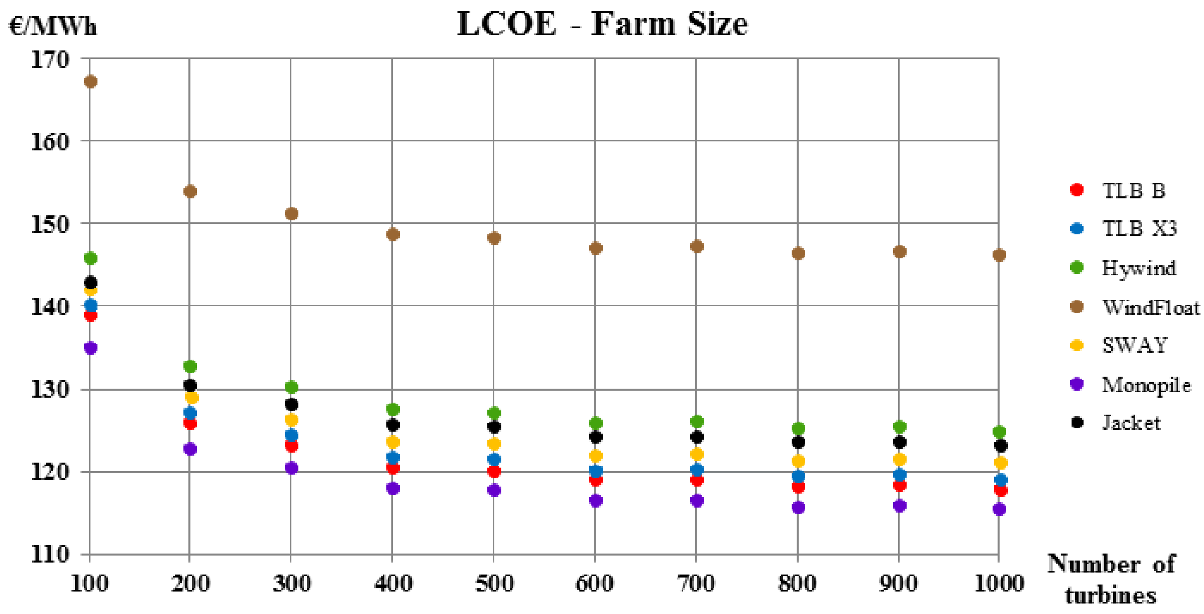


Figure 98: LCOE changes with increasing farm sizes

As indicated, a sudden drop is expected when increasing the farm from 100 to 200 turbines. This is mainly due to assumptions of employment of substations of larger size, with cost increases disproportional to farm size increments. When farms grow to 300 units and up, it is expected to be necessary to introduce further and substations to maintain high O&M availabilities and energy production. Accordingly, LCOEs are assumed to sink at lower rates from 300 units and up, as economies of scale are expected mainly in mobilisation costs, development and consenting costs, as well as administrational and mother vessel costs for O&M.

The step-by-step decline in LCOE with increasing farm sizes is expected from introduction of further substations, accounting for large parts of LCOEs. Additionally, if farm sizes are expected to increase even further, it may be profitable to increase the number of export cables to reduce losses from increased power flow. However, this is not indicated in the evaluations besides calculations of whether one or two cables should be deployed from an economical point of view (Digital Appendix 1).

For the concepts with the lowest baseline LCOE values at benchmark sites, monopiles and TLB concepts, LCOE declines of approximately 16 % are expected through a tenfold increase in farm size. However, of these declines, approximately 10 % are expected to come from a doubling of farm size relative to benchmark size, while approximately 12 % are expected to come from increasing the farms from 100 to 300 units. For the WindFloat concept, with the highest benchmark LCOE values, corresponding declines are expected at 13 % for a tenfold size increase, while making the benchmark farm two or three times larger are associated with declines of approximately 8 % and 10 %, respectively. Accordingly, we may expect higher increases in profitability from making farms two or three times larger than the benchmark farms, than increasing these larger farms even further. For concepts with benchmark LCOE values between these discussed extremals, percentage declines with increasing farm sizes are expected within discussed decline ranges.

However, the presented LCOE values are based on assumptions of uniform and homogenous depth and seabed conditions. In real-life scenarios, it is expected that wind farm locations may not fulfil these assumptions, and that expected LCOE values could change due to requirements to adapt mooring systems for floating concept wind farms, or substructures and even substructure concepts for bottom-fixed farms (Offshore Center Danmark 2012). Wind farm adaptations are expected to increase with increasing farm sizes, as probabilities of site heterogeneity increase. Accordingly, the presented LCOE values may only be considered mere estimates for trends with increasing farm sizes at homogenous locations.

5.2 Offshore Distance

Increasing offshore distances are expected to affect concept LCOEs through three main drivers; increased transport costs for installation of wind turbines and mooring systems, proportionally increased export cable acquisition and installation costs, and increased O&M costs due to offshore distances (Appendix 10). Here, we aim to present how concept LCOEs change with distances set from 100 to 500 *km*, with other costs set at baseline figures. Setting minimum distances to 100 *km* allows for maintenance of set thesis assumptions on evaluations of wind farms deployed at far offshore sites. Additionally, uncertainties with regards to introduction of new cost elements, e.g. AC transmission technologies and logistical operations with regards to wind farm O&M, are best addressed through withholding set assumptions on deployment at far offshore distances.

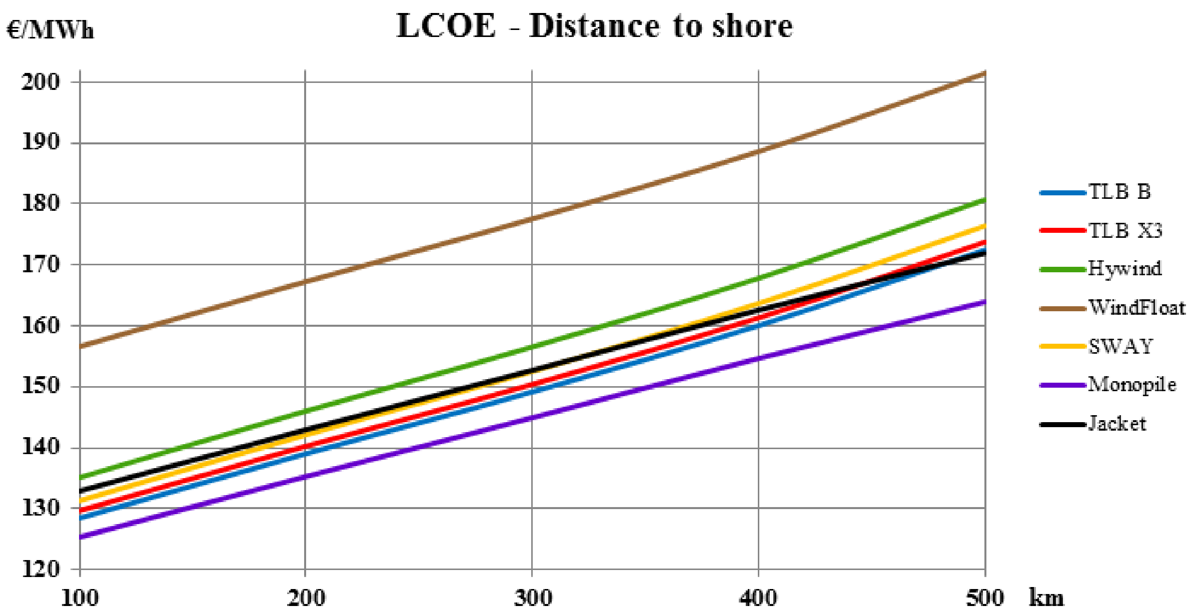


Figure 99: LCOE changes with offshore distance

In Figure 99, LCOEs for all the discussed concepts for offshore distances of 100 - 500 *km* are presented. The figure indicates a trend where LCOE values for bottom-fixed concepts incline at a lower rate than floating equivalents with increasing offshore distances. This is expected to be from costs associated with transport during the installation process. While the actual installation process for at-site installation of wind turbines is expected to be constant and therefore have rather constant costs, the costs associated with transport of the wind turbine and mooring system components to site are expected to increase with distance. For bottom-fixed concepts, these are assigned to several turbines, as the jack-up vessels are assumed to take multiple components per trip. For floating concepts, a number of vessels are included in the individual transportation process (for our chosen installation strategy one AHTS and two tug boats), and the costs associated with these vessels during the transportation processes are not assigned to more than one wind turbine.

As shown, the relation between LCOE and offshore distance seems to be almost linear, with an increase of approximately €^{2013} 10 - 11 per *MWh* for every distance increment of 100 *km*. However, for floating concepts, this value increases to €^{2013} 11 - 13 per *MWh* when distances exceed 300 *km,* due to increased contributions from discussed transport costs.

By halving offshore distance relative to benchmark sites, LCOE values are expected to be reduced by between 6.3 % and 7.6 % for floating concepts. The higher the costs related to towing of the wind turbines, the higher the LCOE value reduction percentages with declining distances, as the relatively high transport costs related to installation processes may not contribute to LCOEs to the same extent as at higher distances. SWAY is the concept which most favours from reduction in distance, as this concept is assumed to have the highest towing costs, presented in Appendix 9, while declining distances are expected to have the smallest impact on the WindFloat concept due to the concept's towing stability and speed, assumed in section 3.3.3.

With distances increasing from benchmark distance to 500 *km*, LCOE values for floating concepts are expected to rise by between 20.4 % and 24.1 %. As expected, WindFloat reacts most favourably on increasing distances, with opposite reactions for SWAY, given assumptions from section 3.3.3.

Bottom-fixed concept LCOEs are expected to be reduced by approximately 7 % with halving of benchmark distance, and to increase by around 21 % by setting distance to 500 *km* instead of 200 *km*.

Both grid connection and O&M costs are expected to be higher for floating concepts, but this difference is not to a large extent expected to be influenced by distance.

5.3 Water Depth

The initial water depths for floating concepts have been set to 200 *m*. Here, we intend to investigate how varying sea depths up to 500 *m* affect levelised costs of energy for the different concepts, with other variables held constant. For floating concepts, these LCOE values are expected to mostly be affected by mooring line costs. As discussed in section 3.3.4, water depth is only expected to have minor influences on mooring system installation costs.

For floating concepts, each concept is assigned depth ranges from concept specific minimum expected applicable depths to depths of 500 *m*. For the TLB concepts, the minimum depth is set to 75 *m*. Hywind, WindFloat and SWAY are assigned minimum depths of 100 *m*, 40 *m* and 120 *m*, respectively.

With increasing depths, mooring lines qualities for catenary mooring systems are expected to remain constant. For optimal performance of taut leg and vertical mooring systems, mooring line stiffnesses are required to exceed minimum ranges regardless of depths, and these stiffness requirements satisfied by adjusting mooring line diameters. Mooring line costs relative to depths are presented in section 3.2.3 and Appendix 6.

Table 41 gives mooring line consumption for various water depths. For catenary mooring systems, the chain consumption near the seabed is assumed constant, at 50 *m* per line.

Table 41: Depth-dependent concept mooring line consumption (m), per wind turbine

Depth	TLB B	TLB X3	Hywind	WindFloat	SWAY
100	934	934	1 500	2 240	-[1]
200	1 766	1 766	1 950	2 840	101
300	2 609	2 609	2 400	3 440	201
400	3 455	3 455	2 850	4 040	301
500	4 302	4 302	3 300	4 640	401

1) Minimum depth set to 120 *m*

For monopile concepts, material consumptions are estimated from scaled substructure weights for certain operational wind farms[3] at various depths. Approximations for depths of 5, 10, 15 and 20 *m* are set to be approximately 470, 735, 850 and 1010 *tons*, respectively. Note that monopile weights are highly site-specific, and that the indicated values only are considered valid as mere estimations to show cost trends. Production costs are estimated similar to section 3.2.2.

For jacket concepts, material consumptions are estimated from jackets suited for deployment at 20 *m* and 50 *m*. For 20 *m* depth, jacket weight is estimated to 500 *tons* and pile weights to 250 *tons*, based on jackets deployed at UK-based Ormonde Offshore Wind Farm (Lindø Offshore Renewables Center 2013). For 50 *m* depth, primary jacket weight is estimated to 545 *tons*, with pile weights at 438 *tons* (de Vries 2011). Production costs are estimated similar to section 3.2.2.

Installation costs for bottom-fixed concepts are considered to be constant, regardless of depths, although the shallowest waters indicated for monopile foundations are expected to be too shallow for majorities of the current jack-up vessel fleet. With use of suitable vessels, actual expected costs may both increase or decrease through differences in expected day rates and capacities.

Figure 100 shows concept LCOE values at varying water depths.

[3] 5 m: Arklow, Burbo Bank. 10 *m*: Lincs, Lynn & Inner Dowsing. 15 *m*: Anholt, Gunfleet Sands, Lincs, Rhyl Flats. 20 *m*: Anholt, Riffgat, Sheringham Shoal. (Lindø Offshore Renewables Center 2013)

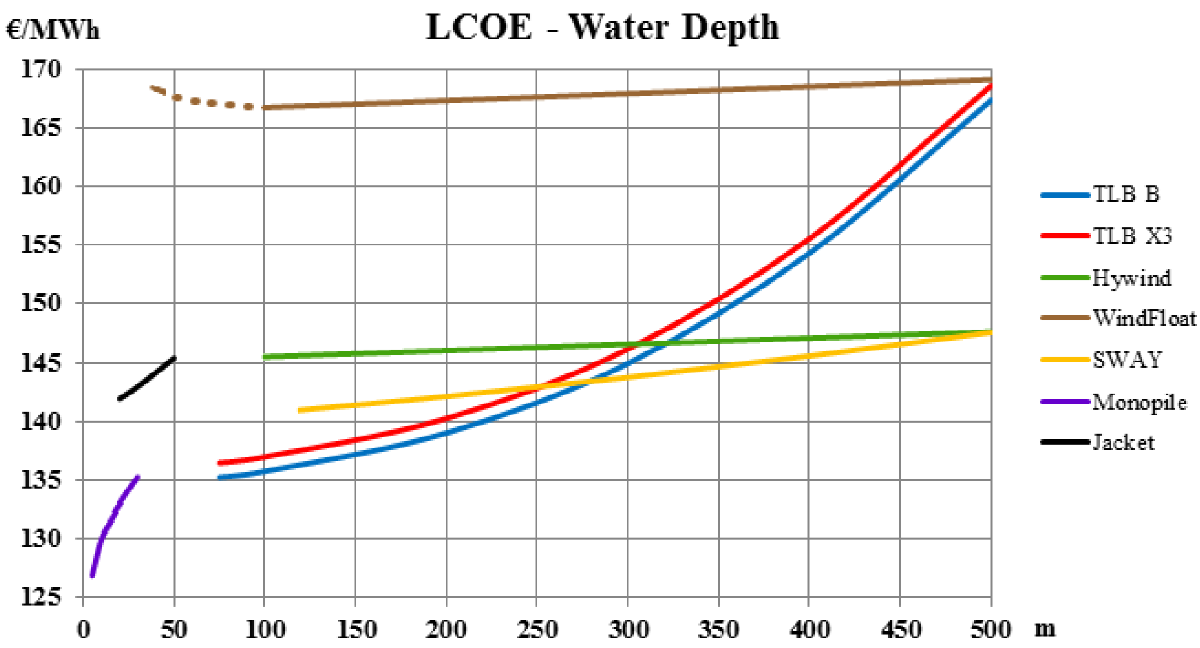


Figure 100: LCOE changes with changes in water depth

The figure indicates LCOE values remain fairly constant for Hywind and WindFloat, as the increase of mooring line consumption is not proportional to depth increments, illustrated in Table 41. Increased water depths are also expected to have small impacts on installation times and capacities, presented in section 3.3.4. The figure indicates the TLB concepts suffer most from increasing depths, as fibre mooring line costs per *m* is expected to increase significantly with increased water depths due to stiffness requirements, presented in Appendix 6. The SWAY concept is also expected to have increased per *m* costs of mooring lines with increasing depths, but not to the same extent as the TLB concepts.

As shown in Figure 98 and Figure 99, LCOE values are expected to change according to farm location parameters, leaving absolute values presented in Figure 100 uncertain for evaluations of concepts with other wind farm qualities than the evaluated benchmark farms. However, LCOE trend developments relative to water depths from Figure 100 are expected valid also for wind farm qualities different from benchmark farms.

The TLB concepts are expected to have the lowest LCOE values when depths are less than approximately 250 *m*, and between 250 *m* and 275 *m*, SWAY seems to become favourable over TLB X3 and TLB B, respectively. When depths increase further, the Hywind concept is expected to have lower LCOEs than the TLB B and TLB X3 concepts at depths in excess of approximately 310 *m* and 325 *m*, respectively. WindFloat seems to become favourable to TLB around 500 *m*. LCOEs for the SWAY concept seems to be favourable relative to Hywind until an assumed depth threshold for the SWAY concept near 500 *m* (Jorde 2013).

The minimum applicable depth for WindFloat is assumed to be approximately 40 *m* (Maciel 2012). However, as mooring line consumption for catenary mooring systems are expected to increase dramatically when depths are less than approximately 100 *m* (Nygaard 2013), and few data on expected actual mooring line lengths seem available, LCOE values for depths less than 100 *m* should only be considered mere estimates for cost trends, indicated through a dashed curve.

Bottom-fixed energy costs are assumed to increase to a much larger extent with increased depths. Note that the indicated LCOE values come from averaged depth-dependent material consumptions of operational wind farms, and may or may not indicate generic trends due to dependency on benthic conditions. Accordingly, these values should be viewed with caution, and are only assumed to be valid as an indication on cost trends.

5.4 Project Life Span

In this section, changes in LCOE with increased wind farm life times are presented. The benchmark LCOE values are for farms producing electricity for 20 years before being decommissioned. However, increasing life spans to 25 or 30 years (Figure 101) are expected to influence LCOE values significantly. With extended life times, the wind turbines are expected to produce electricity for a longer period, while DECEX costs are discounted even further. Expected effects from increased wear and tear with extended life spans are simulated through adding 5 % to the annual OPEX costs for years 20 to 25, and 10 % for years 25 to 30. Note that wind turbine costs are not adjusted according to possible additional production costs needed to extend life spans, possibly leading to somewhat liberal estimations. However, generic sources used for estimating turbine costs indicate possible wind farm life spans of more than 20 years. It is therefore assumed that the deployed turbines are suited for life span extensions. Underwater components are usually required to have expected life spans of at least 30 years.

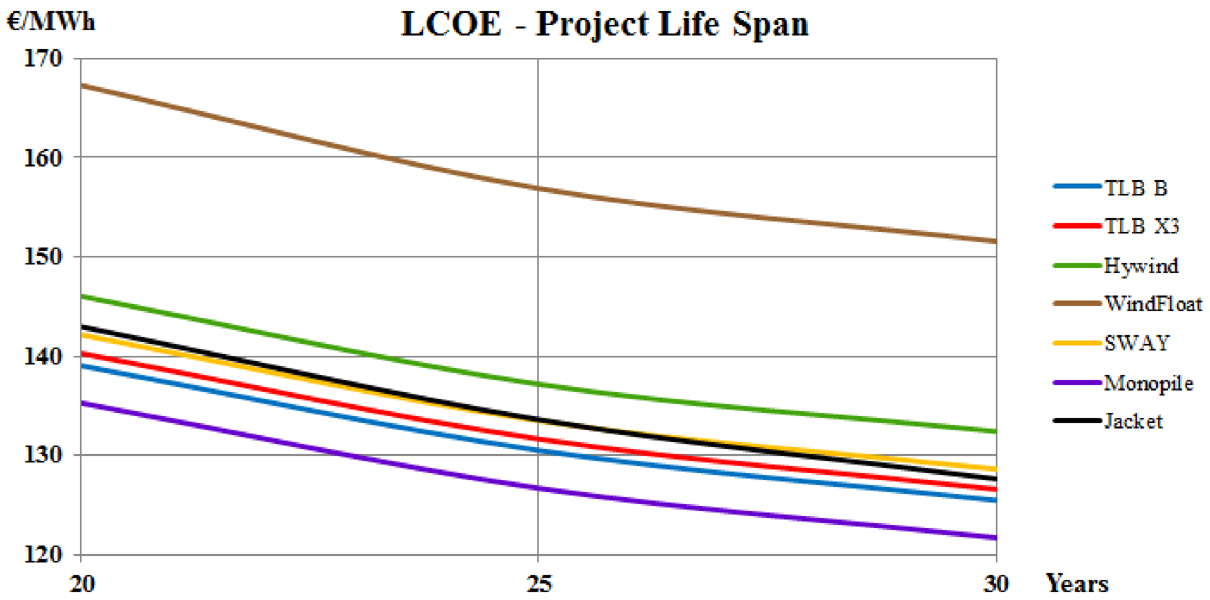


Figure 101: LCOE changes with extended wind farm life spans

As indicated in the figure, LCOE values are expected to fall by approximately €^{2013} 13.5 – 15.7 per *MWh* or approximately 10 %, by expanding the service life of the wind farms by ten years. A five year extension of life span indicates a LCOE drop of approximately €^{2013} 8.5 - 10.4 per *MWh*, corresponding to 6 % - 6.5 %. The highest figures come from the concept with the highest benchmark LCOE, WindFloat, while the lowest figures come from the three concepts with the lowest LCOE values, the monopile and the TLB concepts.

A steeper slope is expected for bottom-fixed concepts than for floating concepts. This comes from the fact that while electricity production is expected equal for all concepts, the floating concepts are expected to have higher OPEX costs, and resultantly, the increase of OPEX costs due to wear and tear is expected to be higher for floating concepts than for bottom-fixed equivalents.

5.5 Optimisation of Farm Qualities

Based on findings from section 5.1 through 5.4, it seems apparent that LCOE values decline with declining offshore distances, water depths, and with increasing life spans and farm sizes. Given these findings, we aim to present how baseline LCOE values for all concepts are expected to be given more optimal wind farm qualities. We aim to present somewhat realistic wind farm qualities with regards to employing present technology, reducing needs of severe wind farm adaptations and reducing unforeseeable risks. Accordingly, wind farms are set to consist of 300 wind turbines (Offshore Center Danmark 2012) with life spans expected at 25 years. To maintain assumptions of deployment at far offshore sites and sustain previous cost estimation feasibilities, the offshore distance is set to 100 *km*. Water depths are set to the optimal depth for all concepts indicated in Figure 100, being 5 *m* for monopiles, 20 *m* for jackets, 75 *m* for TLB concepts, 120 *m* for SWAY and 100 *m* for Hywind and WindFloat

LCOE ranges are presented in Figure 102, based on baseline, low and high costs.

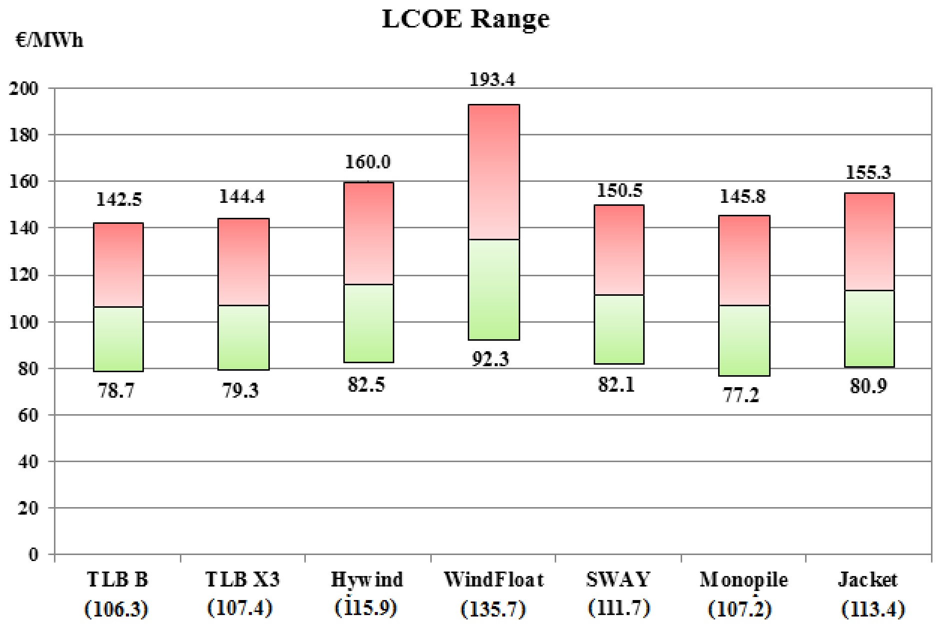


Figure 102: Baseline concept levelised costs of energy at optimised wind farm locations

By comparisons with Figure 93, LCOE values seem to have dropped by approximately €^{2013} 29 - 33 per *MWh*, with LCOEs being in the same order as for benchmark sites. It seems the TLB concepts are expected to see the greatest LCOE declines, both in absolute values at near

€[2013] 33 per *MWh* and relative at approximately 23.5 %, as these concepts are the most water depth sensitive concepts in the analyses. By comparison, it seems jacket structures favour least from reducing water depths with regards to absolute values, while the lowest percentage decline is realised for WindFloat at below 19 %.

Reduction of depths have also indicated TLB concept mooring costs have been reduced so much TLB B LCOE values at 75 *m* are lower than corresponding values for monopiles at 5 *m*.

Further, LCOE ranges if a possible investor is nearer an investment decision for deployment at optimised wind farm sites are estimated, in order to reduce some of the uncertainties related to the optimised LCOE ranges. If an investment decision is to be performed, it is expected that fixed offers on certain components are acquired with only minor uncertainties, while other factors remain somewhat uncertain. Accordingly, some cost elements are fixed at baseline levels, while other are expected to possibly vary within ranges narrower or equal to ranges presented previous in the thesis. The following assumptions are made for estimating optimised LCOE values with lower grades of uncertainty:

1. Development and consenting costs, insurances, turbine costs, production costs, mooring system acquisition costs and electrical component costs are expected to be fixed at baseline levels due to assumptions that fixed offers or tenders are gathered from external producers and suppliers
2. Capacity factors and availabilities are expected to be predictable within ± 1 % from baseline values
3. Vessel rates are expected to be known through short term fixed offers, while expected to potentially vary within thesis ranges on longer terms. Accordingly, installation costs are assumed to be predicted, while O&M costs and decommissioning costs are assumed to be subjected to variations within original thesis ranges

LCOE estimations given these assumptions are presented in Figure 103.

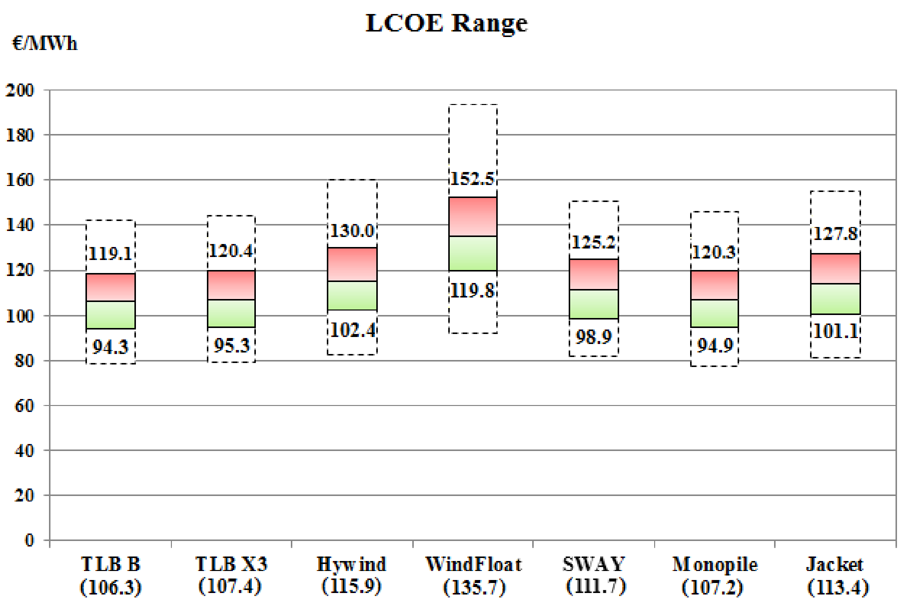


Figure 103: Baseline concept levelised costs of energy at optimised wind farm locations, reduced uncertainties

As expected, baseline LCOE values are expected to remain constant, while LCOE ranges are expected to narrow, as several uncertain factors are assumed known and disregarded. Uncertainties are accordingly reduced from an average span of near 30 % - 40 %, indicated by dashed lines, to spans between approximately 10 % and 13 %.

However, LCOEs are still presented within a certain range, as O&M costs are expected to lie within somewhat wide ranges presented earlier in the thesis.

Please note that actual cost estimations and expected LCOE values may be somewhat different for a potential investment decision, as Figure 103 only aims to illuminate how uncertainties with regards to expected LCOE values could be reduced when approaching FID.

5.6 Quantified Key Cost Drivers

Here, we intend to present how each concept is expected to react to changes in presented cost drivers. Additionally, we wish to investigate how changes in certain key cost drivers besides the already discussed drivers are expected to affect baseline LCOE values for the evaluated benchmark concepts. Concept-specific changes are presented prior to general discussions of not already introduced cost drivers.

Figure 104 through Figure 110 graphically present absolute value impacts on baseline LCOE values at benchmark sites for all evaluated concepts through changes in certain key cost drivers. Asterisked categories indicate cost drivers likely to be uncertain prior to an eventual investment decision. Cost categories not denoted by an asterisk are likely to be decided and evaluated prior to any eventual investment decisions, and are accordingly not expected to greatly influence LCOE uncertainties.

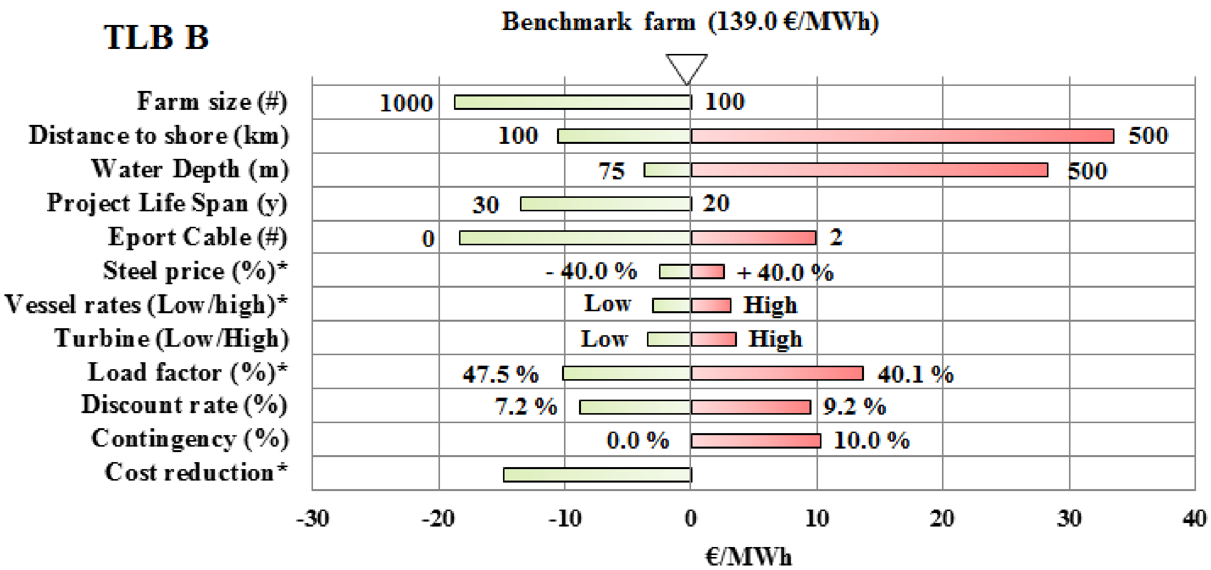


Figure 104: TLB B LCOE sensitivity

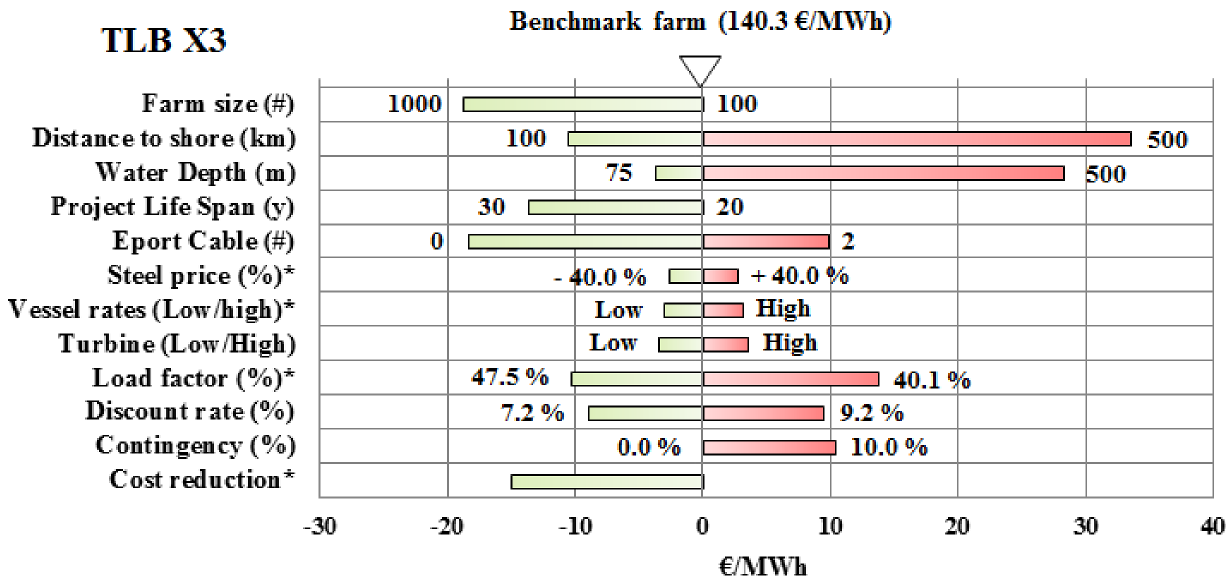


Figure 105: TLB X3 LCOE sensitivity

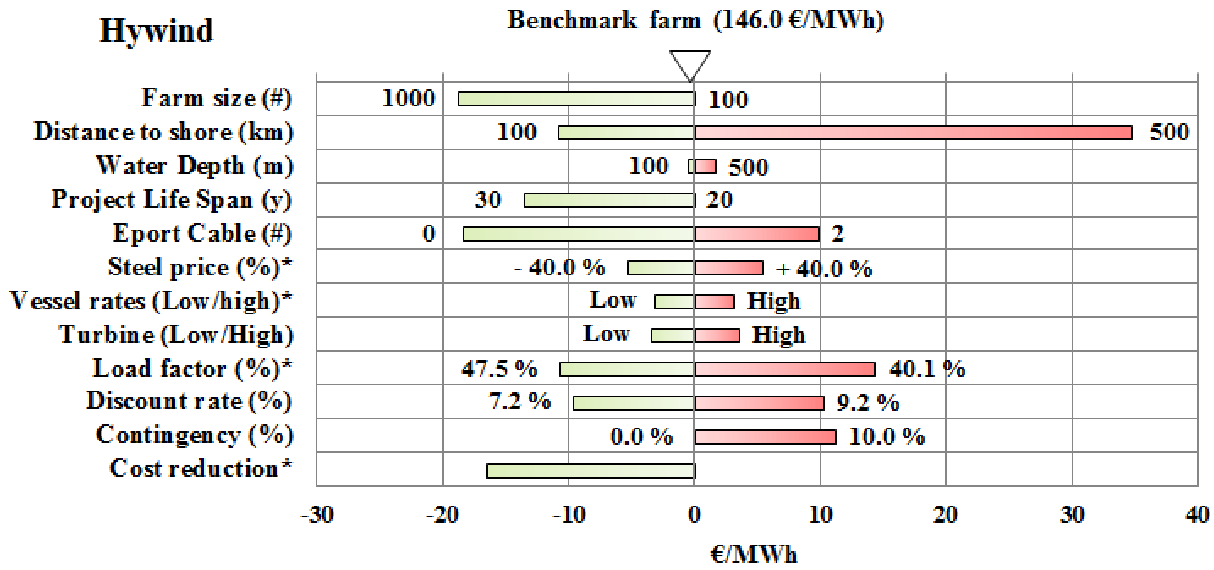


Figure 106: Hywind LCOE sensitivity

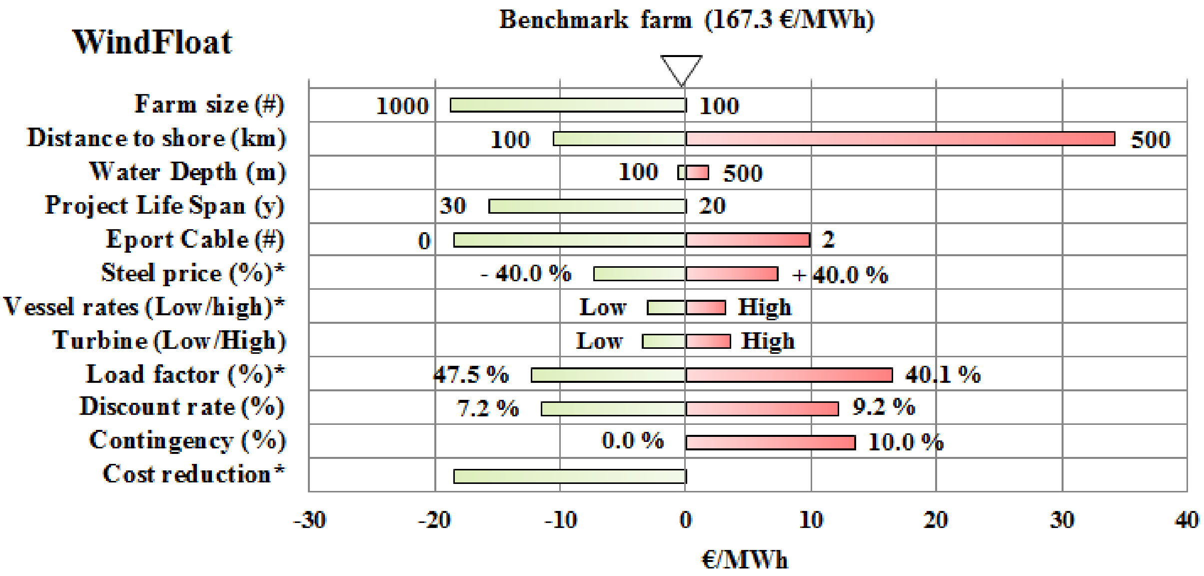


Figure 107: WindFloat LCOE sensitivity

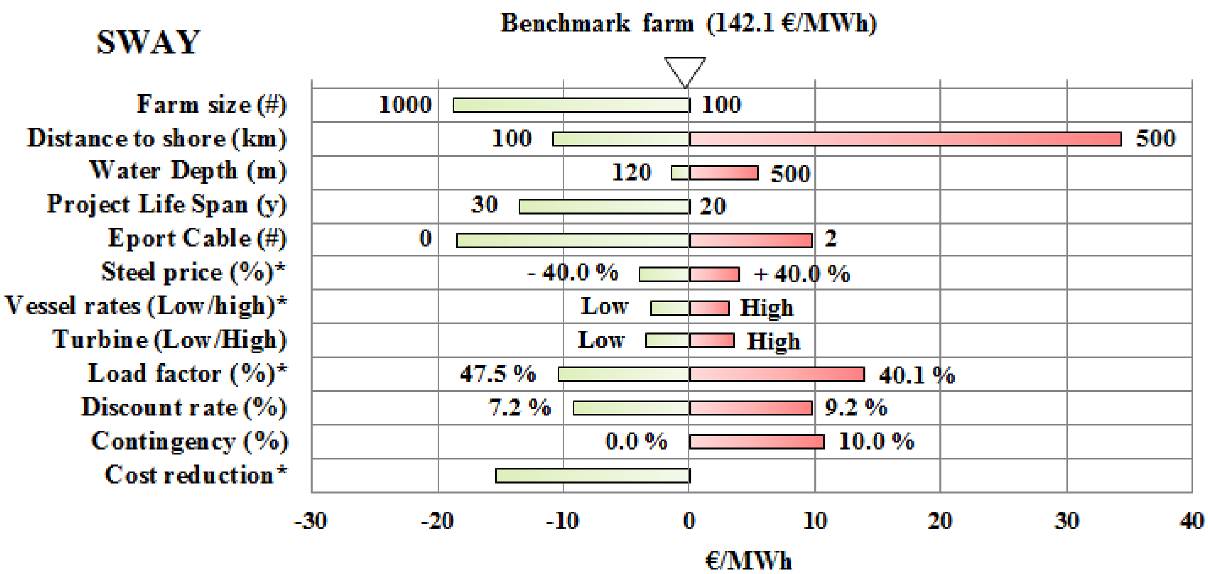


Figure 108: SWAY LCOE sensitivity

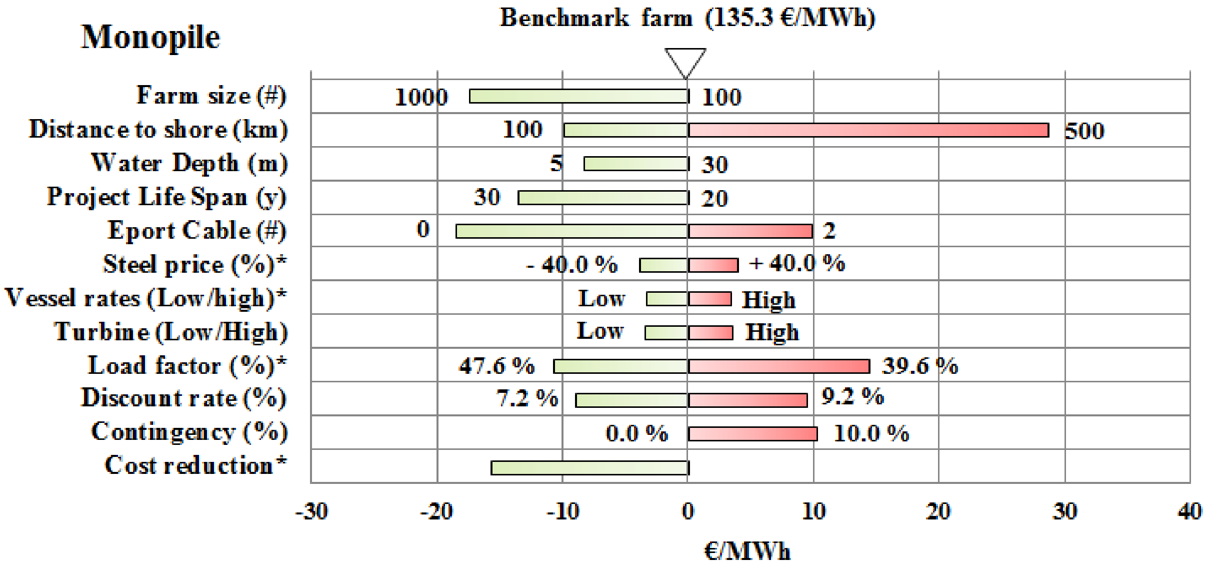


Figure 109: Monopile LCOE sensitivity

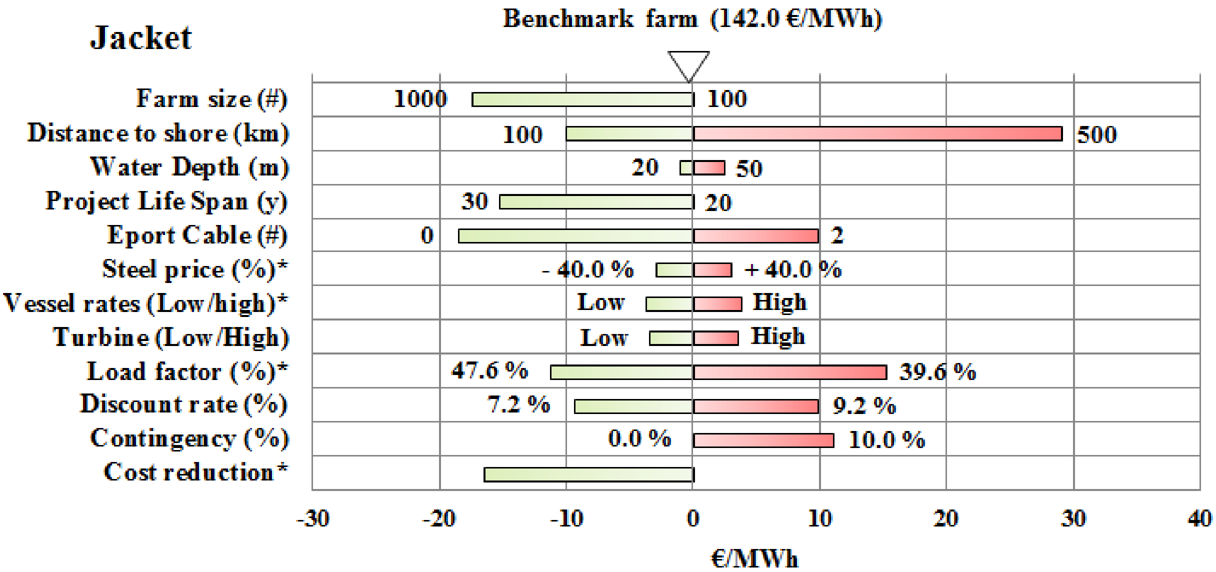


Figure 110: Jacket LCOE sensitivity

As indicated for Figure 104 through Figure 110, all concepts are expected to react similarly with respect to absolute value changes for changes in generic cost drivers, such as farm sizes, offshore distances, life spans, export cable numbers, turbine costs, load factors and discount rates. However, concepts seem to react differently to specific parameters such as water depths, steel costs, vessel rates, contingencies and generic cost reductions. Minor differences between floating and bottom-fixed concepts seem to be expected through different installation processes.

To further illuminate how the different concepts react to changes in key cost drivers, specific changes, both absolute and relative, will be presented for the cost driver categories.

Export Cable Sensitivity

A key cost reduction potential for offshore wind energy could be to employ a European Supergrid, as presented in section 1.1.2. As discussed in section 3.2.4 and Appendix 7, the benchmark farms are to be connected to the mainland grid via one export cable. Positioning of a wind farm in the vicinity of an offshore Supergrid hub could remove the need of an onshore substation, as the grid voltage could be assumed to be close to that delivered by an offshore substation. Additionally, costs related to acquisition and installation of the export cable could be considered negligible with small distances from substation to grid.

With increasing numbers of realised wind farms, it is expected several wind farms will be positioned in clusters close to each other. Accordingly, it may be beneficial for several wind farms to share a common connection to the onshore grid. This is already implemented in German offshore wind farm plans, where offshore substations connecting several farms to shore are owned by the national transmission system operator. Accordingly, the far point of the grid within a wind farm may be a short export cable from an offshore substation, leading to a larger connection substation. (Multiconsult 2012)

Offshore wind farms could also be connected to offshore oil and gas installations, commonly relying on gas turbines for production of electricity. Reducing the dependency on gas turbines could reduce both fuel costs and emissions. To remove dependencies on gas turbines to act as backup energy sources, oil and gas installations and wind farms could possibly share grid connections to shore or to a passing *Supergrid*.

For all concepts, we aim to present how baseline LCOEs for benchmark sites are affected by negliging the export cables and onshore substation, i.e. connecting the wind farms to a proposed, nearby passing Supergrid. We also wish to show effects on LCOEs by increasing the number of export cables to two cables of smaller cross section area, as presented in Appendix 7. Both absolute value changes and percentage changes are presented in Figure 111.

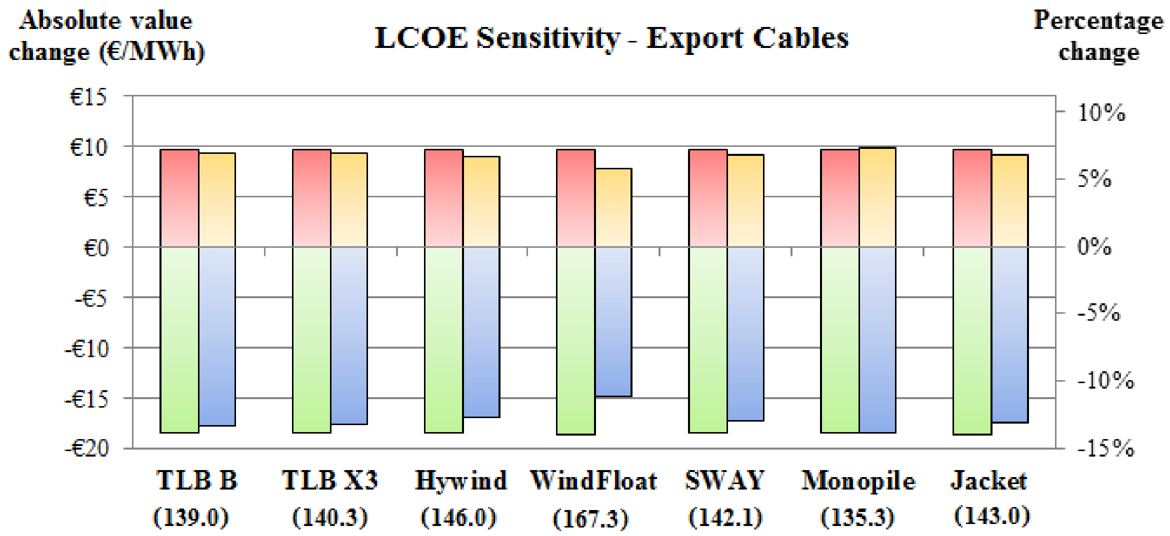


Figure 111: LCOE sensitivity to export cable numbers. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

As indicated, all concepts seem to respond almost identically with respect to absolute LCOE value changes by either disregarding the export cables and onshore substation (below the horizontal axis), or employing two smaller export cables instead of one larger (above the horizontal axis). Reductions in LCOE of approximately €^{2013} 18 per *MWh* are expected by disregarding export cables, while increases of approximately €^{2013} 10 per *MWh* are expected by replacing the baseline export cable with two cables of smaller diameters.

These changes are expected, as identical grid costs are expected for all comparable concepts. Any minor concept differences in absolute value reductions associated with negliging export cables and onshore substations come from the fact that when removing these components, decommissioning costs are changed. When accounting for scrap steel revenues, the concepts are expected to react somewhat differently, but as the DECEX costs are severely discounted, only minuscule differences are expected.

LCOE percentage changes for additions or subtractions of export cables are assumed to be greater the lower benchmark LCOE values are, i.e. highest for monopiles and lowest for WindFloat. Accordingly, the higher benchmark LCOE values are, the less sensitive concepts are to changes in generic parameters such as export cable costs. This is expected, as virtually equal values for all concepts are deducted or added to different benchmark LCOE values. By increasing the number of export cables, LCOE values are expected to rise between approximately 8 % and 10 %, while corresponding figures when negliging export cables and onshore substations are 11 % and 13 %.

Turbine Costs

As indicated in section 4.4, turbine costs are a dominant cost driver for concept LCOE. Accordingly, we aim to evaluate how baseline LCOE values change when turbine costs (excluding towers) are set at low and high levels of ± 10 % relative to the baseline value, derived from lower and higher values of generic sources. These changes are presented in Figure 112, with cost increases and decreases shown above and below the horizontal axis, respectively.

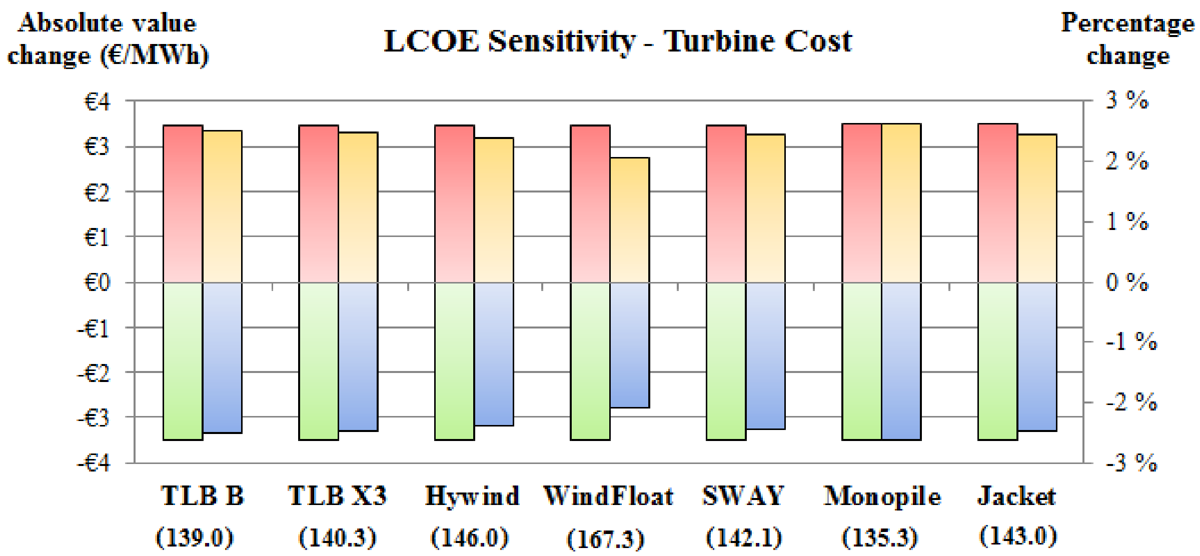


Figure 112: LCOE sensitivity to turbine costs. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

As all concepts deploy turbines of equal costs, a 10 % increase or decrease in turbine costs are expected to either add or deduct approximately €^{2013} 3.5 per *MWh* from benchmark LCOEs, severely less than export cable qualities discussed in previous sections. Since equal absolute values are either added or deducted to different benchmark LCOE values, concepts are expected to be less sensitive to turbine cost changes with increasing benchmark LCOE values.

Steel Costs and Consumption

Another important cost driver is the material costs related to steel consumption. As indicated in section 2.3.1, lower and higher steel costs are assumed at ± 40 %. Accordingly, material costs for turbine towers and floating substructures are altered, while manufacturing costs are held constant. Additionally, costs related to acquisition of RNAs and mooring systems are altered based on their steel weight. Concept LCOE effects are presented in Figure 113, with cost increases and decreases shown above and below the horizontal axis, respectively.

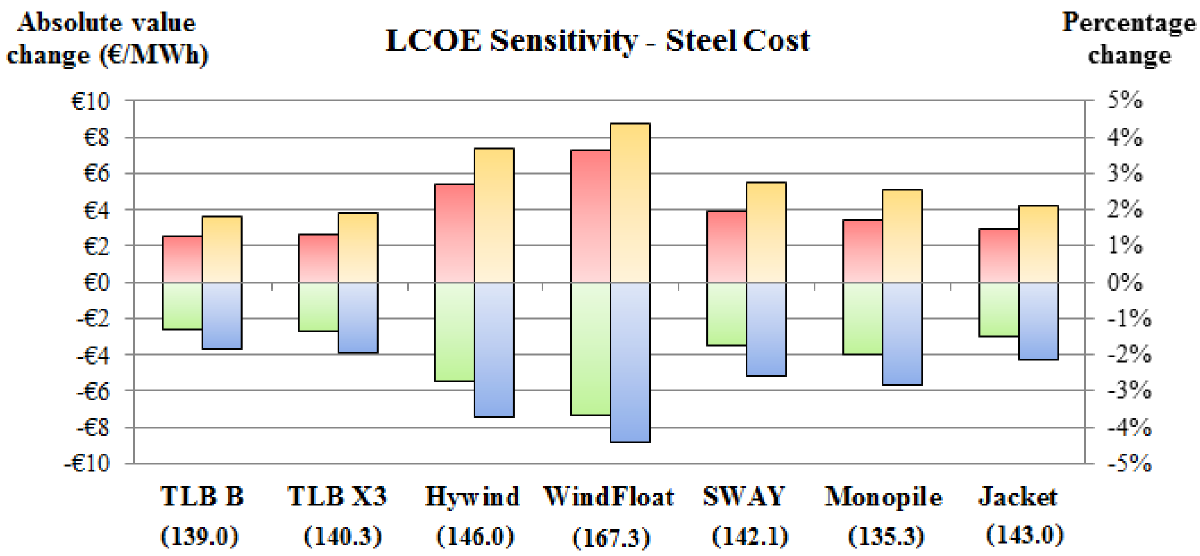


Figure 113: LCOE sensitivity to steel costs. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

Steel costs, in addition to turbine costs and vessel costs, are parameters most likely to be volatile and outside of control for a wind farm constructor through market fluctuations and demand mechanisms. Seeing as the discussed concepts vary greatly in steel consumptions, changes in steel costs are expected to have highly differentiated impacts on all concepts. In absolute values, the concepts with the highest steel consumptions, WindFloat and Hywind are expected to suffer or gain most from increasing or decreasing steel costs. Heavy substructure concepts seem to be more affected by steel cost changes than lighter constructions, disproportionate to trends shown for relative generic cost changes with respect to baseline LCOE levels shown in Figure 111 and Figure 112.

By comparisons with Figure 112, it seems an equal percentage change in turbine and steel costs do not account for equal LCOE changes, as turbine costs account for larger portions of the total LCOE than steel costs, shown in Figure 94. Accordingly, it seems offshore wind turbines are more sensitive to turbine cost changes than steel cost changes. With maturing offshore wind industries expecting greater competition and more entrants, it may also be assumed turbine cost changes may be more affected than steel cost changes, as a 10 % short-term turbine cost change seems more plausible than a 40 % steel cost change.

In addition to indicating material costs, concept steel consumptions may also serve as an indication of impact on global steel distribution, given large-scale production. The annual steel production is estimated to approximately 1 520 million *tons* (Elliott et al. 2013), and if a hypothetical large-scale wind turbine production volume were to occupy larger amounts of the global steel production, impacts on worldwide steel prices may be likely to be seen.

Table 42 presents the amount of global, annual steel production consumed through producing 100, 1 000 or 10 000 of the evaluated wind turbine concepts, including steel used for mooring systems for applicable concepts.

Table 42: Steel Consumption Footprint

Number of Turbines	100	1 000	10 000
TLB B	0.01 %	0.06 %	0.61 %
TLB X3	0.01 %	0.07 %	0.66 %
Hywind	0.01 %	0.14 %	1.44 %
WindFloat	0.02 %	0.20 %	1.97 %
SWAY	0.01 %	0.09 %	0.89 %
Monopile	0.01 %	0.11 %	1.10 %
Jacket	0.01 %	0.09 %	0.86 %

As indicated, production of 100 turbines does not seem to consume any large portions of the global steel production. When increasing this number to 10 000, it seems that concept material consumptions account for approximately 0.6 % to 2 % of global steel production. With these figures, it is expected that global steel price may be affected, but quantifications of these impacts is expected to be best performed through extensive simulations accounting for several variables. It is expected that mass production of the most steel-intensive the evaluated concepts, WindFloat and Hywind, would affect global steel prices the most of the evaluated concepts. However, for this thesis, it is decided that steel price fluctuation effects are evaluated adequately through estimating LCOE differences with steel cost changes of ± 40 %.

Vessel Rates

Day rates for installation vessels and external O&M vessels are expected to be extremely volatile. Accordingly, LCOE values for changes in installation vessel rates from low to high estimates presented in section 2.3.2, with all other costs are held at baseline levels, are presented. For OPEX cost influences on LCOE, vessel rate fluctuations are simulated through assigning day rate changes of ± 20 % on all external vessels used for unplanned maintenance operations, while costs associated with mother vessels or specialised maintenance vessels are changed according to low and high estimates presented in section 2.3.2. LCOE effects with changing vessel costs are presented in Figure 114, with cost increases and decreases shown above and below the horizontal axis, respectively.

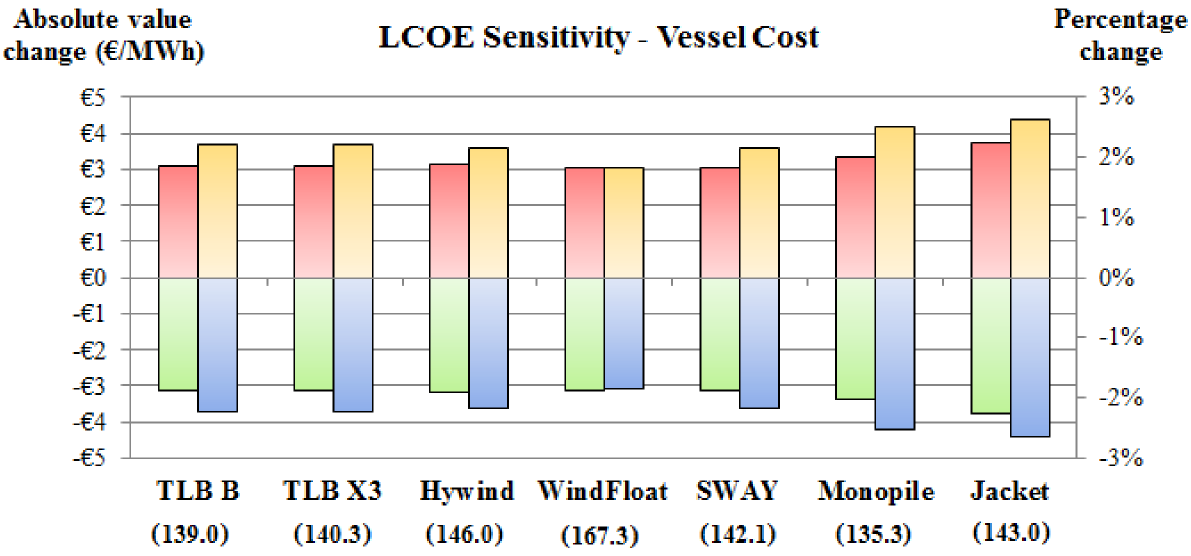


Figure 114: LCOE sensitivity to vessel rates. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

The figure indicates that floating concepts are less sensitive to changes in vessel day rates than bottom-fixed concepts, both with regards to absolute and relative values. This is likely because floating installation costs are estimated to be lower than bottom-fixed installation costs, relying on less expensive vessels. Vessel costs are market dependent, and accordingly expected not to be directly foreseeable by wind farm developers. Adequate attention to this should be paid if an investment decision were to be performed.

As presented in section 3.3.3, all floating concepts are expected to have similar installation procedures and costs, and OPEX costs are set to be similar. Accordingly, floating concepts are expected to react similarly to vessel costs with regards to absolute values, leading to somewhat different percentage changes based on benchmark LCOE differences. As bottom-fixed concepts require more costly installations from vessels expected to be more expensive than those used for floating concepts, bottom-fixed concepts seem to be more sensitive to vessel cost changes than their floating equivalents.

By comparison with Figure 112, it seems concept vessel cost sensitivities are comparable with turbine cost sensitivities within the thesis extremals.

Load Factors

Baseline capacity factors are set to 53 % for all concepts. Changes in baseline LCOE with capacity factors in the region of 50 % to 56 % are presented, which, when combined with low- and high case farm availabilities, leads to net load factors for floating concepts of between 40.1 % and 47.5 %, with bottom-fixed equivalents somewhat different due to availability simulation differences, indicated in Digital Appendix 1. LCOE sensitivities with changing load factors are presented in Figure 115, with effects from lowering or amplifying site load factors above or below the horizontal axis, respectively.

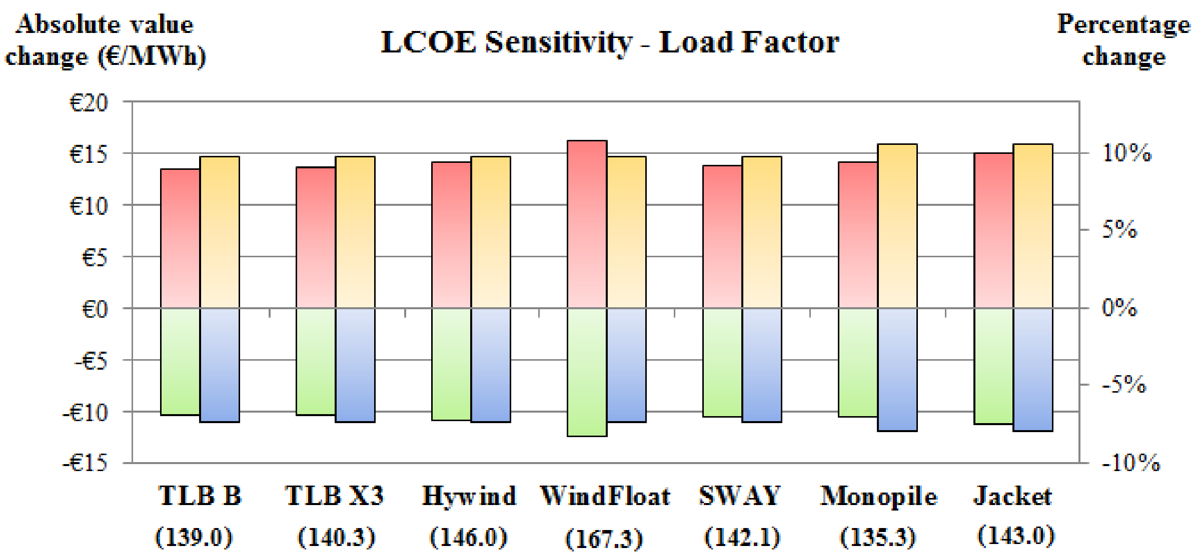


Figure 115: LCOE sensitivity to load factors. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

As shown in Figure 115, it seems positioning wind farms at sites with capacity factors 3 % higher or lower than what could be achieved using deployed generic 5 *MW* turbines at the benchmark farm site could reduce or increase overall LCOE values by approximately 10 %. Energy production is highly dependent on realised conditions, and a 3 % change of capacity factors for a 500 *MW* is expected to change annual gross energy production (before accounting any other losses than those from capacity factors) equivalent to the annual average electricity consumption of nearly 7 500 EU dwellings (Nikiel & Oxley 2011). Accordingly, adequate meteorological surveys and availability simulations are key prior to positioning and construction of an offshore wind farm to better predict energy costs, although real-life weather conditions never could be expected to be certainly predicted.

As concept benchmark LCOE values are different, concepts react dissimilarly to load factor changes with respect to absolute values, as concepts with higher benchmark LCOE values are expected to experience higher absolute value changes with load factor changes.

Any minor percentage sensitivity differences between floating and bottom-fixed concepts may be attributed to simulated availabilities, and should be considered equal.

Discount Rates

Benchmark discount rates are set to 8.2 %. Depending on risk aversion, discount rates may be set lower or higher, and here, LCOE changes with discount rates changed by ± 1 % from benchmark rates are presented in Figure 116.

As the LCOE value by some may be interpreted as the *break-even* price for energy, the required discount rate for an investment or a series of investment may influence the discounted energy cost. A risk-averse investor may require a higher risk premium on his or her investment than an investor more prone to taking risks. This would lead to higher costs of capital, and the risk-averse investor would accordingly require higher energy prices to experience breaking even on investments.

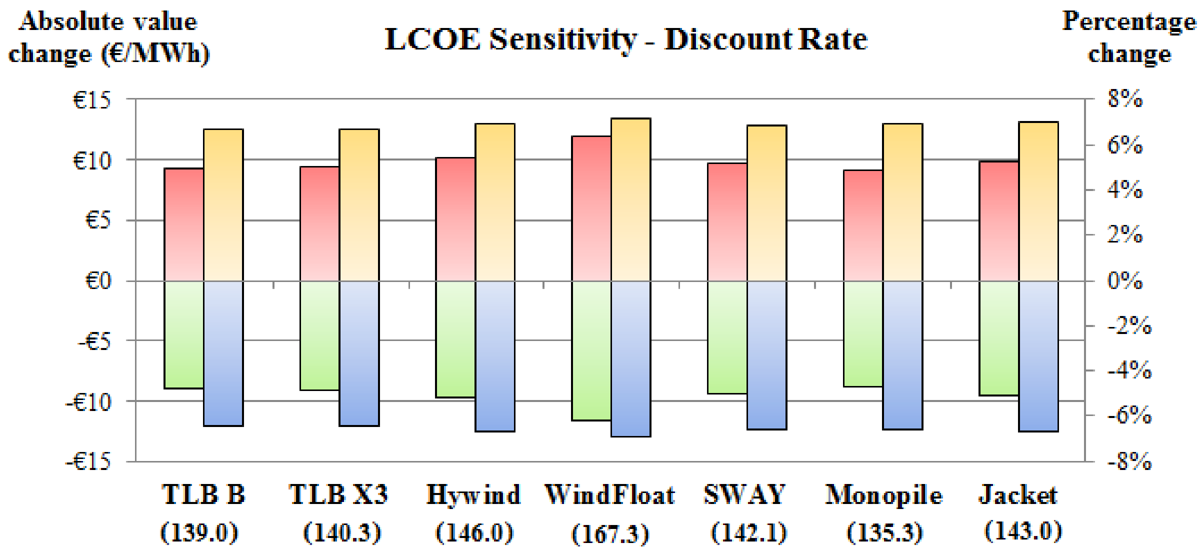


Figure 116: LCOE sensitivity to discount rates. Red and green indicate negative and positive absolute value effects, respectively, while yellow and blue indicate corresponding percentage changes

Figure 116 presents LCOE sensitivities to 1 % changes in discount rates. As indicated, all concepts are expected to react with similar relative LCOE changes by changing discount rates, as costs are discounted on similar grounds for all concepts. Changing discount rates by 1 % leads to expected relative LCOE changes of approximately 7 %. However, with different level of benchmark LCOE, concepts react differently with respect to absolute value changes, at approximately €^{2013} 9 per *MWh* for concepts with the lowest benchmark LCOEs, to approximately €^{2013} 12 per *MWh* for concepts with the highest LCOE values.

The employed and preferred discount rate for an investment project is expected to depend on several factors, such as level of desired risk exposure for specific investors, expected risk within a market or an industry, and country-specific risks and support mechanisms. Accordingly, attention to required discount rates should be paid in case of investment decisions.

Contingencies

In order to counteract LCOE effects from unforeseeable events not covered by insurances, contingencies may be introduced as a percentage on CAPEX costs. Here, LCOE changes coming from implementing contingencies up to 10 % on baseline CAPEX values are presented in Figure 117. Contingencies may particularly be a feasible solution for risk-averse investors.

As contingencies are added to concept dependent CAPEX values, these are expected to influence LCOE changes both in regards to absolute and relative values. From Figure 117 it seems 10 % contingencies add approximately 8 %, or between €^{2013} 10 – 13.5 per *MWh* to benchmark LCOEs. However, if contingencies are introduced and not utilised due to lack of unfortunate events, constructors are expected to be able to cut the presented values from their overall energy costs, as contingencies are likely to be realised through funds or accounts earmarked unforeseeable events. By comparisons with Figure 112, Figure 113 and Figure 114, it seems implementations of 10 % contingencies for all concepts may almost or completely counteract market fluctuations increasing both turbine costs, steel costs and vessel costs, as these are expected to be market dependent and outside of a wind farm developer's control.

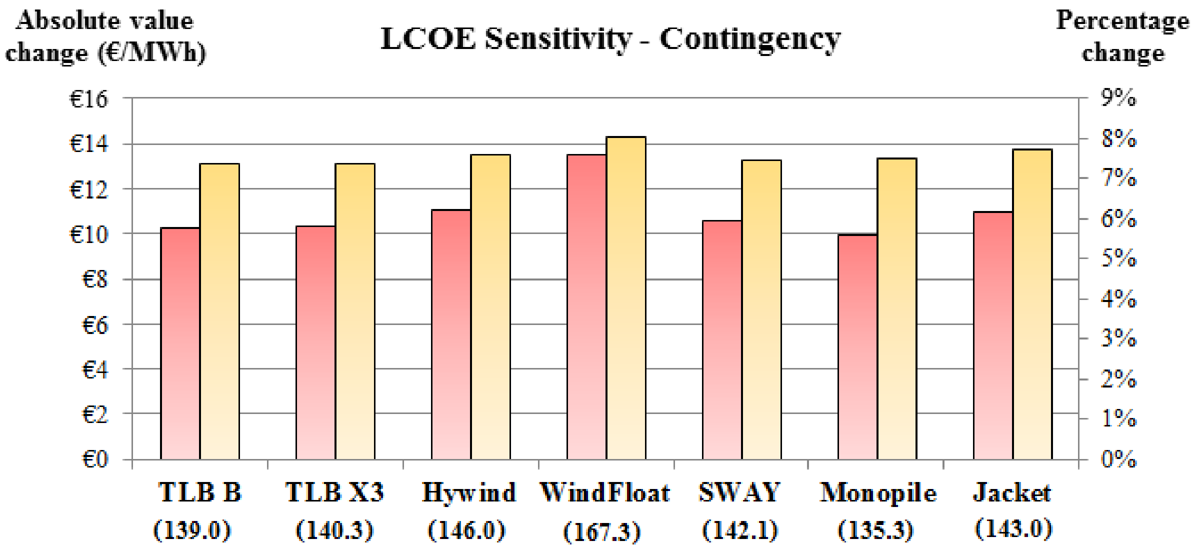


Figure 117: LCOE sensitivity to contingency implementations. Red and yellow indicate negative absolute value and percentage change effects, respectively

Other Cost Reduction Potentials

Generic sources indicate that both CAPEX and OPEX costs may be reduced significantly in the future. These cost reductions may be attributed to both technological developments in components, such as introduction of new materials and technologies to reduce costs of turbines, substructures, grid connections, installations and O&M, economies of scale, e.g. through standardisation and scaling, and learning from the existing oil and gas industry (Scottish Enterprise 2011).

The employed cost reduction potentials are presented in Table 43. Cost reduction potentials are further introduced in Appendix 12, while LCOE effects are presented in Figure 118.

Table 43: Employed cost reduction potentials

Cost drivers	Cost reduction percentage
Turbine	15 %
Substructure	10 %
Grid Connection	10 %
Installation	15 %
Operation and Maintenance	15 %

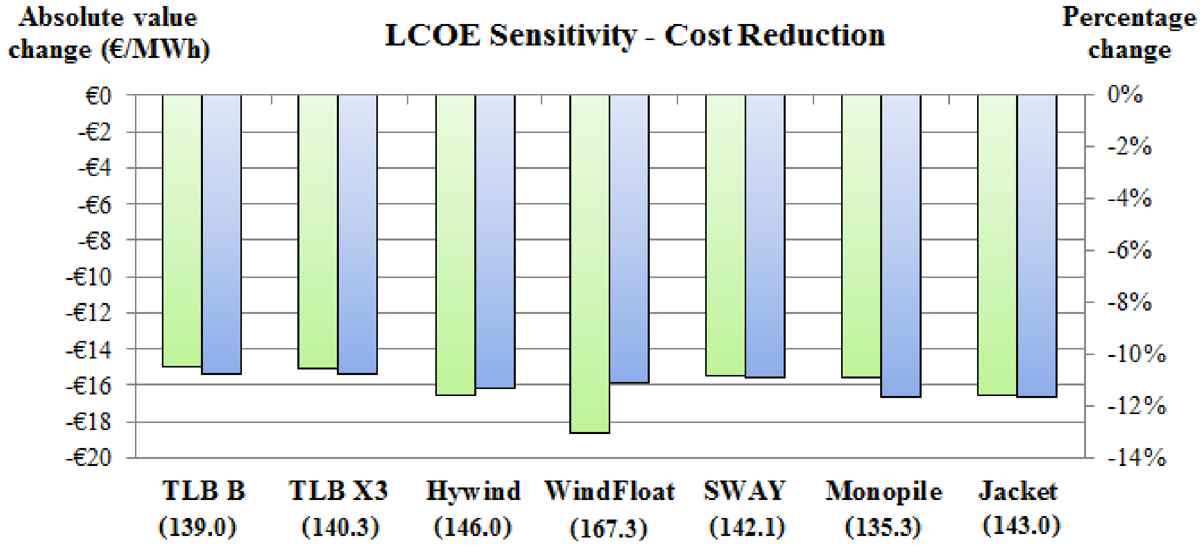


Figure 118: LCOE sensitivity to generic cost reductions. Green and blue indicate positive absolute value and percentage change effects, respectively

As indicated, concept LCOEs are expected to react differently to generic cost reductions, both with regards to relative and absolute changes, as generic cost reductions are expected to influence both parameters shared for all concepts, such as turbine and grid connection costs, and concept specific parameters, such as substructure production costs.

Generic cost reductions are expected to be between approximately €^{2013} 15 - 19 per *MWh*, depending on benchmark LCOE values. Corresponding relative reductions are expected at between 10 and 13 %, indicating high concept sensitivity to cost reductions.

6. CONCLUSION

6.1 Evaluation

For this thesis, we have aimed to evaluate all relevant costs occurring during the life cycles of offshore wind farms. Five floating and two bottom-fixed concepts have been investigated, and costs related to concept wind farm development, construction, operation and disengagement have been estimated. These costs have been distributed over the wind farm life cycles based on when they are expected to occur, and accordingly discounted to levelised values based on set discount rates, resulting in levelised costs of energy (LCOE) associated with each concept. Further, sensitivities with respect to key cost drivers have been evaluated.

To serve as basis for all analyses, a fictitious benchmark site for all concepts is defined, positioned 200 *km* offshore at a generic Northern European offshore location. From sensitivity analyses, it became apparent that expected LCOE values could be significantly lowered by reducing offshore distances and water depths, extending life spans and increasing wind farm sizes. Accordingly, LCOE values for a more optimised, while still realistic wind farm scenario was computed.

Based on optimised site values, it seems TLB B wind turbines indicate lowest levelised costs of energy, at $€^{2013}$ 106.3 per *MWh*, with monopile based bottom-fixed wind turbine levelised costs of energy approximately 1 % above values for the TLB B concept. With reduced offshore distances, these costs could be expected to be reduced even further However, the TLB concepts are expected to be highly sensitive to increasing water depths, and are also expected to be associated with higher risks in events of mooring line failures. The two evaluated concepts associated with highest energy costs at optimised sites are expected to be Hywind and WindFloat, respectively at $€^{2013}$ 115.9 and $€^{2013}$ 135.7 per *MWh*. These cost differences are mainly attributed to steel consumption and associated production costs. For the benchmark site, LCOE values are generally approximately 25 % to 30 % higher than at the optimised sites. These differences are mainly attributed to economies of scale and offshore distances. Acquisition and installation of export cables severely contribute to CAPEX costs and LCOE values, rendering wind farms sensitive to offshore distances. With increased depths, the TLB B concept loses its cost advantage over monopiles, resulting in lowest benchmark LCOEs at $€^{2013}$ 135.3 per *MWh*.

From our findings, it seems floating concepts may be competitive to bottom-fixed concepts, through less expensive installation and in some cases production operations, although mooring systems contribute to costs for floating concepts. Based on present European wholesale electricity prices expected in the region of $€^{2013}$ 40 - 50 per *MWh*, it seems offshore wind energy is not an economically viable solution from a socioeconomic perspective. However, with widely different support levels from country to country (Appendix 3), offshore wind energy, both floating and bottom-fixed, could for some concepts at certain locations be economically justifiable from a wind farm operator's point of view. Nevertheless, it seems clear costs have to be cut even further to ensure competitiveness towards other sources of energy production. The main focus should be set on reducing turbine costs, grid connection costs and O&M costs, as these are expected to influence levelised costs of energy the most.

6.2 Further Work

As indicated in section 3.3.3, the favourable installation solution for all floating concepts seems to be onshore integration of substructures and towers and installation of turbine components in protected waters, before wind turbines are towed to offshore sites. This installation strategy has already been proven through installations of the Hywind and WindFloat pilot turbines. Accordingly, a key focus while further developing floating concepts may be to ensure possibilities for vertical towing operations, although development of experimental installation methods focusing on reducing the number of vessels employed per installed wind turbine involved should also be targeted.

Depending on the number of assumptions set prior to estimating certain CAPEX cost elements, an increasing number of uncertainties exist. Uncertain elements include production costs and installations processes for floating substructures, and, accordingly, costs related to large-scale production and installation of floating concepts should be investigated in further detail. This could mainly be through evaluation of automated welding costs computed from detailed geometries in specialised production facilities, as well as costs associated with large-scale lifting and installation operations performed using floating vessels.

Additionally, simplifications are set for how costs are assumed to change with increasing farm sizes. Since farms size is a cost driver concepts seem highly sensitive to, any scale effects should be investigated further to estimate an optimal farm size with regards to both economies of scale, technical and logistical feasibilities and investment risks. Economies of scale could potentially be realised through mutual sharing between developers, e.g. of facilities and technologies for production, installation and operation.

Effects of water depth changes should be investigated further for all concepts. More accurate substructure dimensions for bottom-fixed concepts and mooring line properties for floating concepts should be calculated. This is especially important for the TLB concepts, which suffer most from increased water depths due to stiffness requirements. Any possible concept differences with respect to O&M operations should be investigated further. A generic and simplified approach has been used to estimate costs related to detaching and towing wind turbines to shore for repairs, and further and more thorough investigations of such costs could reveal key differences in preferred maintenance strategies between concepts. Further technological development should also be implemented in O&M estimations. As indicated in chapter 5, LCOE values are highly sensitive to offshore distances. With reduced distances, other transmission technologies (e.g. HVAC) would be expected to be employed, and cost reduction potentials associated with such technologies relative to those presented in this thesis should be investigated further.

Generally, costs should be investigated with further attention to detail based on their expected impact on levelised costs of energy, given by Figure 94, as any relative changes in large cost categories would indicate larger LCOE impacts than similar changes in less intrusive cost categories. In general, main drivers for LCOE values may be attributed to turbine costs, grid costs and O&M costs. Accordingly, focus should be set on both clarifying and reducing these cost categories, through simulations, research and technological developments.

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8. APPENDIX

8.1 Written Appendices

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Support Mechanisms for Renewable Energy

Appendix Table 1 is a summary of offshore wind operating support mechanisms currently in use across Europe, while Appendix Table 2 shows key advantages and disadvantages associated with the incentive strategies.

Appendix Table 1: Incentive strategies in Europe (Navigant Consulting Inc 2013)

Country	Primary Incentive Strategy	Notes
Belgium	Green certificates with floor price (i.e., Feed-in Premium)	- Separate green certificate markets in Brussels, Flanders, and Wallonia plus federal obligations - Offshore wind is supported at the federal level.
Denmark	Premium FiT for land-based wind, tender scheme for offshore wind, and fixed FiTs for others	- Premium duration 22 000 peak load hours (nine to ten years)
Finland	FiT	- 12-year tariff - “Sprinter Bonus” (i.e., additional tariff) for projects built in the first 3 years
France	FiT and tender for large projects	- Offshore wind 1.9 GW allocated in tenders in April 2012 at tariffs in the 17-20 *cEUR/MWh* range
Germany	FiT	- Offshore wind 20-year FiT with annual digression of 7% starting from 2018 - Offshore tariff at 15 *cEUR/kWh* for 12 years, or 19 *cEUR/kWh* for 8 years, plus extra period at 15 *cEUR/kWh* depending on distance and depth
Ireland	FiT	- Offshore wind 0.14 *cEUR/kWh* - 15 years capped at 1.5 GW
Italy	Tendering with floor price	- Projects of 5 *MW* and larger based on average lifetime of plants - Not yet approved
Netherlands	FiT via CfD	- Premium capped at 14.4 *cEUR/kWh* for offshore wind and 7.6 cEUR/kWh for land-based wind - Duration 15 years
Norway	Green Certificates	- Green certificates at 2.16 *cEUR/kWh* in 2011
Poland	FiT and quota obligation	- Minimum price based on formula - 10.4 % of all energy produced should be from renewable sources
Portugal	FiT (subject to ongoing review)	- Licensing of all RE projects suspended
Spain	FiT (subject to ongoing review)	- Moratorium on subsidies for all RE capacity not already approved
Sweden	Market spot price + green certificates	- Offshore wind GC + Premium until 2030
U.K.	Green certificates (”ROCs”) Under review (EMR)	- Quotas increase until 2037 - 2 ROCS for offshore wind - Buyout price set by government (penalty for utilities not reaching quota) with such penalties recycled to producers’ pro rata production

Appendix Table 2: Incentive strategy advantages and disadvantages (Navigant Consulting Inc 2013)

	Advantages	Disadvantages	Lessons Learned
Feed-in Tariff (FiT) and Feed-in Premium	- Applies to actually produced electricity, avoiding *windfall* effects, generally favoring the most productive sites. - Encourages owners to conduct long-term O&M - Ultimately paid by electricity consumers and not by taxpayers, ensuring a logical burden allocation - Can provide the public with a long-term hedge against increasing power prices. - Least expensive and most effective way to build up renewable energy capacity if the program is designed and implemented well.	- Can encourage over-investment if prices are set at too generous levels, leading to windfall effects. - Can be hard to determine the right level of a FiT/FiP to obtain the maximum amount of green electricity with a minimum amount of subsidies. - FiP flows less stable than FiT equivalents due to electricity price dependency	- Should be guaranteed for long durations to spread costs over enough volume - Rates to new entrants should reduce over tim to support technological improvement. - Projects should not be allowed to switch to market prices during the FiT period, in order for the public to keep the full benefit of the price hedge against increased energy prices. - Administrative burdens need to be considered.
Quotas / Green Certificates	- Is market-based and thus “technology neutral.” Allows competition between different renewable energy technologies through the price for the green certificates and should in theory lead to the least expensive technologies being put in service to reach the desired quota. - Quotas can be adjusted over time, giving policymakers a more direct tool to control the level of investment in renewable energy.	- Prices of green certificates can be highly volatile due to uncertainty in future obligations and supply. - Makes investors carry significant volume risk, discouraging investment, or generates *windfall* revenues for utilities. - Project delays may lead to quota price increments, leading to quotas not reached. - Generally, green certificate regimes lead to higher costs for consumers, confusion amongst investors, politicians, and the public, and less political support.	- A minimum price for the green certificates appears to be necessary in immature markets to insure investment security. - The obligation quota should be set with a long time horizon in order to stimulate investment in the supply chain. - Generally, green certificate regimes lead to higher costs for consumers, confusion amongst investors, politicians, and the public, and less political support. - Difficult for new and unproven technologies to penetrate the market.
Tendering	- Visibility on renewable energy investment volumes and future production - Visibility on cost for the regulator - Competition between bidders that should ensure the lower cost options are developed	- Depending on the level of competition, prices may or may not be aligned with the regulator’s expectations. - Once the regime is allocated to an investor or set of investors, the government has no certainty that the investment will actually take place; investors can change their minds or meet adverse circumstances.	- A penalty for non-compliance to the contracted tender should be implemented to avoid low bids that are not feasible in the end. Important to have a balanced volume allocated in each tendering round. When the total volumes tendered are too high, there will be limited competition and high prices.

Appendix 4

Monetary Conversions

Currency conversion

Monetary values are converted to Euro values at source publication year using annualised average conversion rates by the following relation:

$$€^t = \frac{V^t}{X^t} \qquad \textbf{\textit{(I)}}$$

Where:

$€^t$ denotes Euro cost converted from foreign currency at time t of source

V^t denotes the monetary value stated in foreign currency at time t

X^t denotes currency conversion cost between Euros and foreign currency at time t

t denotes the time of source publication

Inflation

After conversion to Euros (at the time of the source publication, given that source does not state monetary values in Euros), all values are inflated to present day values using EU-15 *Total Industrial Producer Price Indices* by the following relation:

$$€^{2013} = €^t \cdot \frac{I^{2013}}{I^t} \qquad \textbf{\textit{(II)}}$$

Where:

$€^{2013}$ denotes present day Euro values

$€^t$ denotes Euro cost converted from foreign currency at time t of source

I^{2013} denotes the present day Total Industrial Producer Price Index (122.30, 2005 = 100)

I^t denotes the Total Industrial Producer Price Index of time t of source

t denotes the time of source publication

Appendix Table 3: Conversion rates and index values

Year	USD[1]	GBP[1]	NOK[1]	PPI Index[2]
2013	1.33	0.83	7.38	122.30
2012	1.29	0.81	7.48	122.28
2011	1.39	0.87	7.79	119.50
2010	1.33	0.86	8.01	112.78
2009	1.39	0.89	8.73	109.03
2008	1.47	0.80	8.23	113.59
2007	1.37	0.68	8.01	106.85
2006	1.26	0.68	8.04	104.56
2005	1.25	0.68	8.01	100.00
2004	1.24	0.68	8.37	95.96
2003	1.13	0.69	8.00	94.10

1) (Oanda Corporation 2013)
2) (Eurostat 2013)

Appendix 5

Manufacturing Cost Additions

As indicated in section 3.2.2, an approximate ratio of total production costs and material costs of turbine towers could be estimated at 3:1 given our baseline bulk steel costs and overall tower costs indicated as an average value of generic sources, shown in Table 13. This total estimated production cost supports indications of (de Vries 2011).

As for production costs for bottom-fixed substructures, an addition of approximately 100 % on monopile material costs is indicated (de Vries 2011; Faaij & Junginger 2004), while an addition of 300-500 % on jacket material costs is suggested (Borgen 2010; de Vries 2011). These are based on large-scale production in a rather mature industry, but bottom-fixed substructure design depend on special adaptation to site, not only to the general wind farm site, but also to the benthic conditions of the installation site assigned to each individual wind turbine (Jensen 2010). Accordingly, bottom-fixed substructures have to be individually engineered, and may be regarded as not completely mass-produced.

For floating substructure production in a future, mature industry, a broader standardisation of designs may be expected, leading to assumptions on some cost reductions of manufacturing costs through mass productions. However, floating substructures often contain stiffeners leading to complex manufacturing processes.

For this thesis, the expected complexity of the evaluated floating concept substructures are discussed with advisor Anders Myhr. This appendix contains some of the key points stated during the discussions.

Hywind

Statoil suggests a 100 % addition on material costs from materials that have experienced some coarse modifications (Byklum 2013). The baseline steel costs indicated in this thesis may be regarded somewhat liberal with modifications in mind, and the expected complexity of the structure (e.g. from stiffeners, diameter transitions, sealing lids and mooring line mounts) leads to a suggestion to set manufacturing costs to 120 % of baseline material costs.

TLB B / TLB X3

The TLB B bears physical resemblances to the Hywind concept. However, the reduced steel weight leads to potentially easier handling, and manufacturing cost additions are accordingly set somewhat lower, to 110 %. The TLB X3 concept is expected to be slightly more complex with regards to manufacturing processes due to transitions between the small transition pipes, the floater component and the tower transition peace. Resultantly, additions are set to 130 %.

WindFloat

The WindFloat concept is both large and expected to be highly complex to manufacture, with stiffeners and heave compensation. (Borgen 2010) suggests an addition of 480 % on material costs, but due to possibilities of large-scale dry-dock production, this is considered too much of a conservative estimate. Accordingly, additions are set to 200 %.

SWAY

The SWAY concept is not completely symmetrical, and with changes in diameters and wall thicknesses (Jorde 2013), in addition to yaw systems and tension rods, manufacturing costs additions are set to 150 %, corresponding with estimates by (Borgen 2010)

Total baseline production costs are summarised in Appendix Table 4.

Appendix Table 4: Production cost estimates for floating substructures

Concept	**TLB B**	**TLB X3**	**Hywind II**	**WindFloat**	**SWAY**
Material consumption (costs)	445[1]	521[1]	1 700[2]	2 500[3]	1 100[4]
Material costs	€ 445 000	€ 521 000	€ 1 700 000	€ 2 500 000	€ 1 100 000
Manufacturing costs addition	110 %[5]	130%[5]	120 %[2.5]	200 %[5.6]	150 %[6]
Manufacturing costs	€ 489 500	€ 677 300	€ 2 040 000	€ 5 000 000	€ 1 650 000
Total production costs	**€ 934 500**	**€ 1 198 300**	**€ 3 740 000**	**€ 7 500 000**	**€ 2 750 000**

1) Source: (Myhr & Nygaard 2012)
2) Source: (Byklum 2013)
3) Source: (Weinstein 2009)
4) Source: (Jorde 2013)
5) Source: (Myhr 2013)
6) Source: (Borgen 2010)

Appendix Figure 1: Manufacturing of the WindFloat pilot substructure

Appendix 6

Fibre Rope Mooring Line Costs

Two main requirements have to be fulfilled for all mooring lines used in taut leg mooring systems:

1) The mooring lines have to have a minimum breaking load of at least 1 800 *tons*, whereof 1 000 *tons* come from substructure excess buoyancy, and 800 *tons* from load amplitudes induced by wave and wind loads, currents etc. (Myhr 2013)
2) Mooring line stiffnesses, i.e. the product of cross section area and elastic modulus in relation to mooring line length has to exceed minimum set values for all applicable depths. These required minimum stiffness values are $8 \cdot 10^6\ {}^{N}/_{m}$ for the upper mooring lines and $5.6 \cdot 10^6\ {}^{N}/_{m}$ for the lower mooring lines. (Myhr 2013)

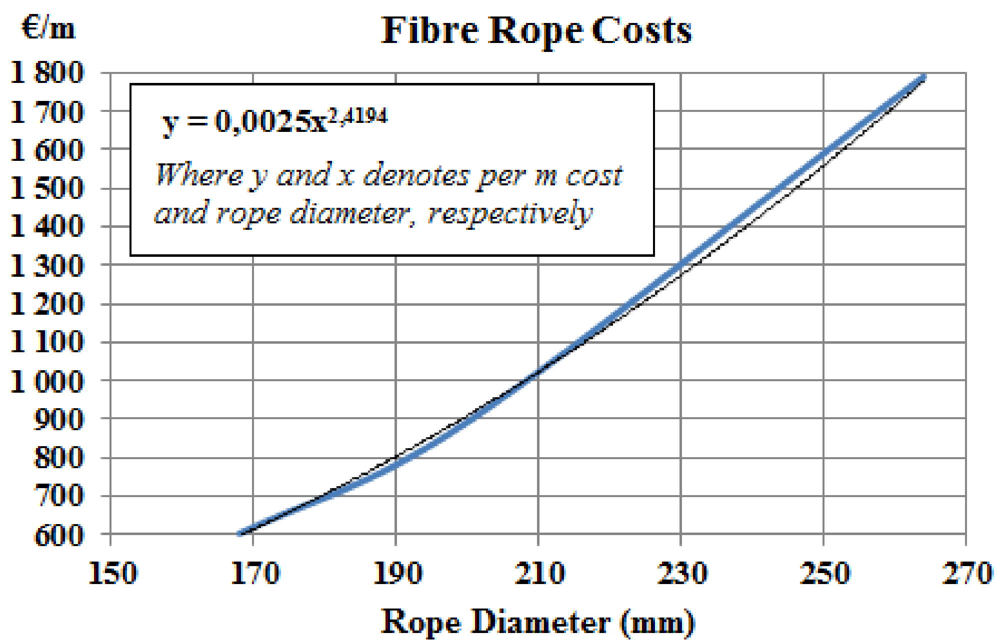
To serve as basis for the cost analyses, per *m* costs for certain dimensions of Dyneema SK75 fibre mooring lines are gathered, based on information from (Shahid 2013). These costs are presented in Appendix Table 5.

Appendix Table 5: Dyneema mooring line properties

Diameter (*mm*)	**Minimum Break Load (*tons*)**	**Per *m* cost (€^{2013})**
168	1 800	602
200	2 540	893
264	4 420	1 790

As indicated, all mooring lines are expected to have diameters of at least 168 *mm* to maintain breaking load requirements. Based on minimum TLB concept depths set to 75 *m*, and 100 *m* depth increments from 100 *m* to 500 *m*, mooring line consumptions are calculated.

From an expected Dyneema SK75 modulus of elasticity of 113 *GPa* (DSM Dyneema 2009), it is investigated whether 168 *mm* mooring lines are sufficient for use at desired depths. If not, minimum necessary mooring line diameters and corresponding expected costs are calculated. These costs are based on assumptions that line diameters may be made to order given demand for severe lengths, and that diameter dependent costs may be estimated from a power function found through simple regression analyses performed on the data points using MS Excel. Diameter dependant per *m* cost developments and corresponding power function estimations are presented in Appendix Figure 2. These indications are assumed valid in an approximate diameter region from 168 *mm* to 264 *mm*.



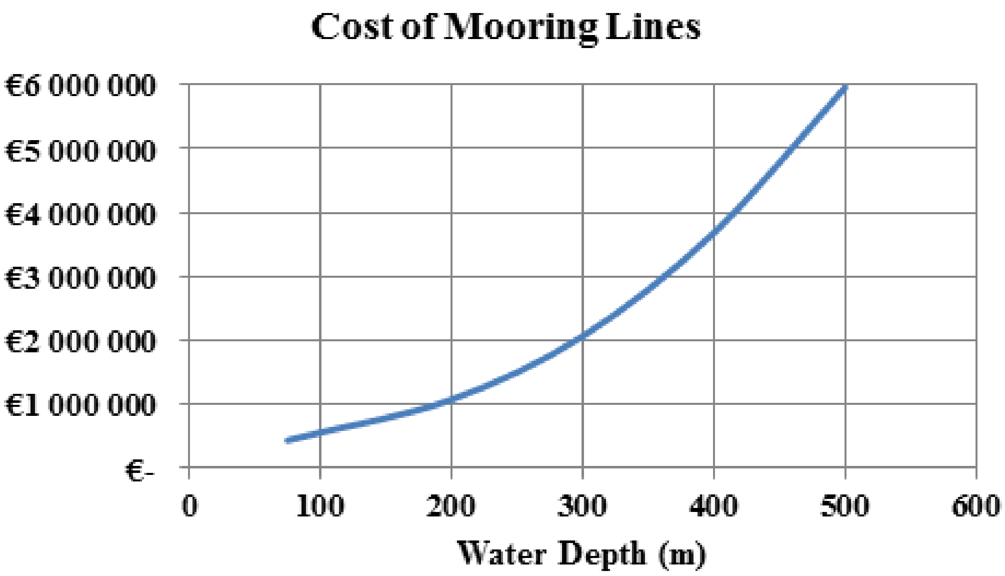
Appendix Figure 2: Diameter dependant cost estimations for fibre ropes used for TLB concepts

Appendix Table 6 shows mooring line cost estimates per *m* of upper or lower mooring line at different water depths.

Appendix Table 6: Cost estimations, fibre ropes

	Depth (*m*)	**75**	**100**	**200**	**300**	**400**	**500**
Upper line	Mooring line length (*m*)	141	177	318	460	601	743
	Stiffness (*N/m*)	$1.8 \cdot 10^7$	$1.4 \cdot 10^7$	$7.9 \cdot 10^6$	$5.4 \cdot 10^6$	$4.2 \cdot 10^6$	$3.4 \cdot 10^6$
	168 *mm* line OK?	Yes	Yes	No	No	No	No
	Required diameter (*mm*)	-	-	169.4	203.5	232.8	258.7
	Estimated per *m* cost (€^{2013})	602	602	617	963	1 332	1 720
Lower line	Mooring line length (*m*)	103	135	270	410	551	692
	Stiffness (*N/m*)	$2.4 \cdot 10^7$	$1.9 \cdot 10^7$	$9.3 \cdot 10^6$	$6.1 \cdot 10^6$	$4.5 \cdot 10^6$	$3.6 \cdot 10^6$
	168 *mm* line OK?	Yes	Yes	Yes	Yes	No	No
	Required diameter (*mm*)	-	-	-	-	186.4	208.9
	Estimated per *m* cost (€^{2013})	602	602	602	602	778	1 025

Based on the mooring line consumption at different water depths, the relation between water depth and mooring line costs per wind turbine of the TLB concepts are presented in Appendix Figure 3. As indicated, with increasing depths, both mooring line consumption and mooring line costs per *m* increase, and accordingly, with increasing depths, an almost exponential total mooring line cost development is expected with increasing water depths.



Appendix Figure 3: Cost of mooring lines relative to water depths

Please note that uncertainties exist with regards to the viability of use of Dyneema fibre ropes for permanent, taut leg mooring systems due to creep properties, and presently, polyester ropes are frequently used for permanent moorings, although not showing the same stiffness properties as Dyneema ropes (Shahid 2013). However, the thesis is delimitated towards problems associated with mooring creep through assumptions that these may be adequately addressed with future technologies, either through further development of the actual mooring line properties or through development of systems capable of counteracting mooring line creep.

Appendix 7

Grid Connection

This appendix comprises information relevant for estimating costs associated with grid connections.

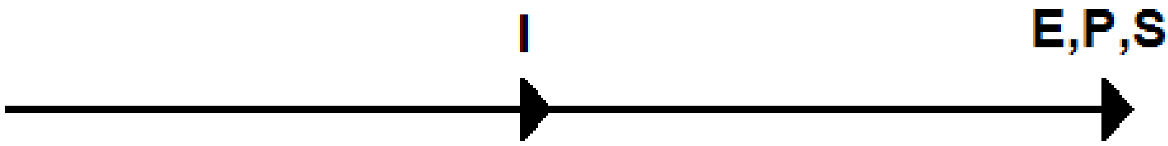
Electrical Losses

Electricity generating data for the REpower 5M, on which the generic 5 *MW* turbine deployed in the thesis is based, is shown in Appendix Table 7 below.

Appendix Table 7: REpower 5M data (REpower Systems 2011)

REpower 5M data	
Generator type	Double-fed asynchronous, 6-pole
Generator power	5075 kW
Output voltage	660 V
Speed	750-1170 rpm
Gear ratio	1:97

According to (Wildi 2006), a double-fed asynchronous motor run as a generator behaves like a synchronous generator as the generator provides itself with reactive power needed to magnetise the stator. This leads to no phase offset between the voltage E and the current I, giving a phase angle φ of 0°, thus resulting in no reactive power Q delivered to the grid, while the apparent power S equals the rated, active power P.



Appendix Figure 4: Voltage/current relation and power triangle for double-fed asynchronous generator

Appendix Figure 4 illustrates the relationship between power P, current I and voltage E for a certain rated power fed from a three-phase generator G through a transformer onto a direct-current grid at rated voltage.

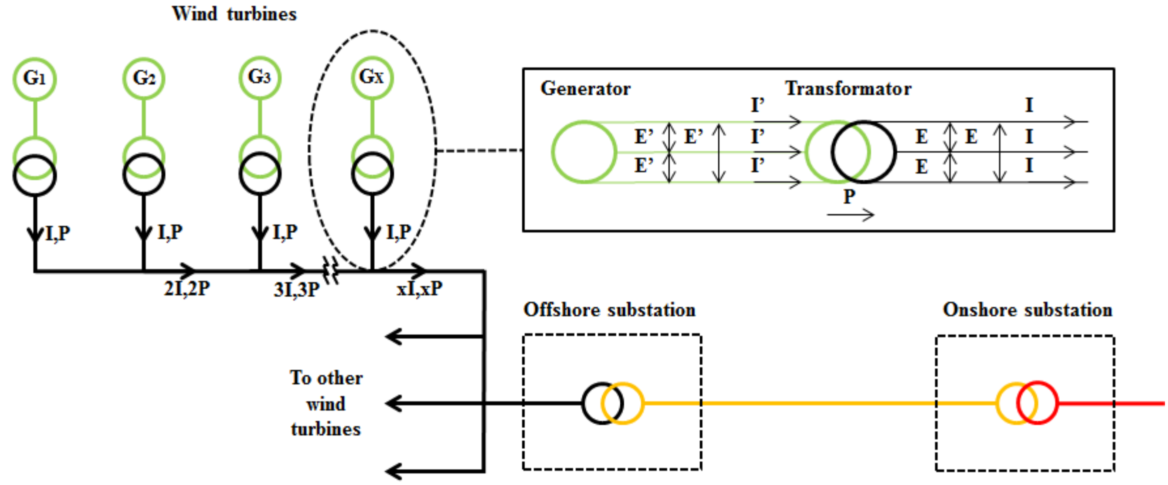
The voltage and current before reaching the transformer are irrelevant for power loss calculations. If the transformer ups voltage to 33 *kV*, assuming rated power of 5000 kW and no transformer power losses, grid current can be found using the following relations, keeping in mind apparent power S and active power P are equal:

$$\mathrm{P} = \mathrm{S} = \sqrt{3} \cdot \mathrm{E} \cdot \mathrm{I} \qquad \textbf{\textit{(III)}}$$

$$\mathrm{I} = \frac{\mathrm{P}}{\sqrt{3} \cdot \mathrm{E}} = \frac{5.0 \cdot 10^6 \ \mathrm{W}}{\sqrt{3} \cdot 3.3 \cdot 10^4 \ \mathrm{W}} = 87.5 \ \mathrm{A} \qquad \textbf{\textit{(IV)}}$$

These currents and voltages are shown in the upper right part of Appendix Figure 5.

When power from multiple generators are fed onto the same grid, grid voltage must stay the same, requiring grid current to increase with the same factor as power increase, obvious from the power to voltage and current relation shown above. This is demonstrated in the one-line-diagram in Appendix Figure 5.



Appendix Figure 5: Power and current adding up

Current losses in a cable are given by:

$$P_{loss} = I^2 \cdot R \qquad \textit{(V)}$$

where:
P_{loss} denotes ohmic power losses
I denotes grid current
R denotes cable resistance

The resistance is calculated through:

$$R = \frac{\rho \cdot l}{A} \qquad \textit{(VI)}$$

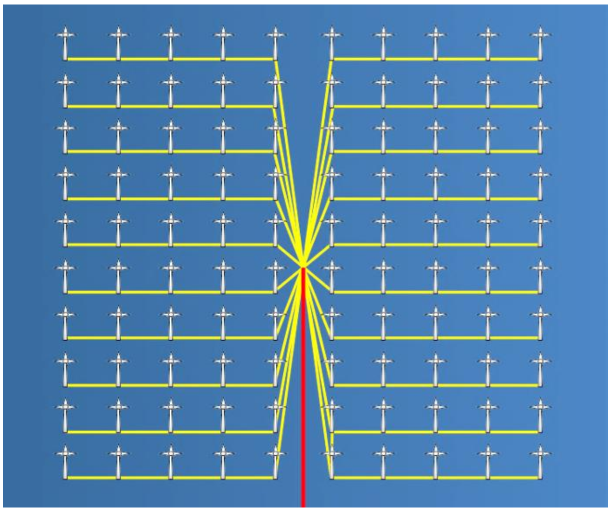
Where:
ρ denotes material-specific electrical resistivity (for this thesis set to copper resistivity, $1{,}75 \cdot 10^{-8}\ \Omega m$)
l denotes the cable length
A denotes the cable cross-sectional area

Combinations of these relations show that ohmic losses in a homogenous cable grid at given voltage depends solely on cable length and cable current, which in turn depends on added power.

The mentioned power loss qualities are derived from three-phase circuit calculation, but are also relevant for ohmic losses in single-phase DC circuits.

Inter-array Cable Structures

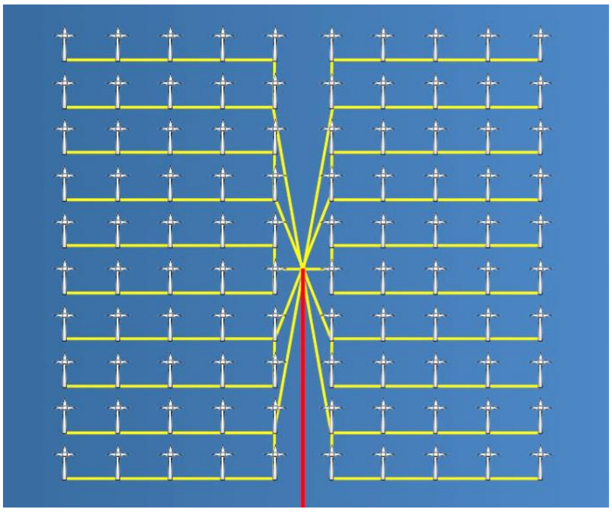
Four possible inter-array cable structures are presented, with associated costs further introduced in Digital Appendix 1.



Appendix Figure 6: Cable structure case 1

Inter-array cable properties	
Total cable length	191.6 *km*
Cable type	33 *kV* cobber cable (300 mm^2)
Max power*	500 *MW*
Max percentage power loss	0.68 %
Average power*	224*MW*
Average percentage power loss	0.31 %

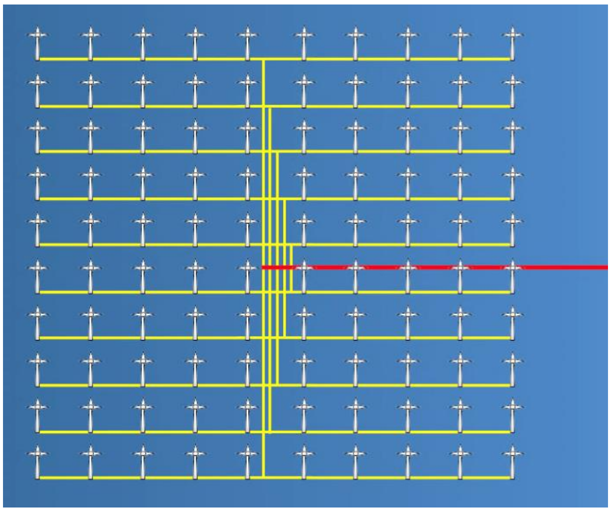
* Transmitted within the farm



Appendix Figure 7: Cable structure case 2

Inter-array cable properties	
Total cable length	171.9 *km*
Cable type	33 *kV* cobber cable (300 mm^2)
Max power*	500 *MW*
Max percentage power loss	1.11 %
Average power*	224*MW*
Average percentage power loss	0.50 %

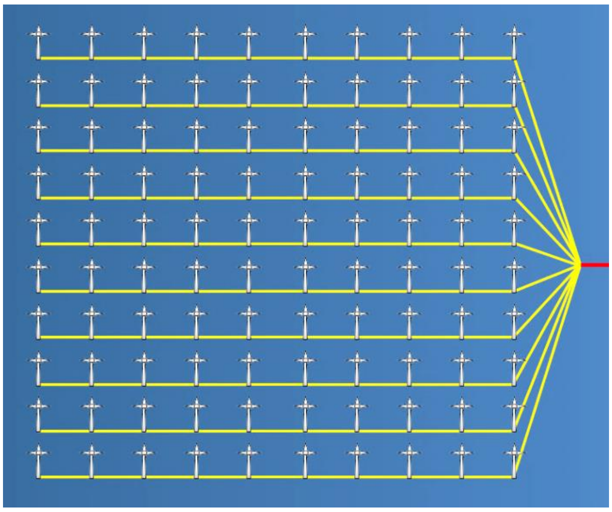
* Transmitted within the farm



Appendix Figure 8: Cable structure case 3

Inter-array cable properties	
Total cable length	172.0 *km*
Cable type	33 *kV* cobber cable (300 mm^2)
Max power*	500 *MW*
Max percentage power loss	1.11 %
Average power*	224*MW*
Average percentage power loss	0.50 %

* Transmitted within the farm



Inter-array cable properties	
Total cable length	175.8 *km*
Cable type	33 *kV* cobber cable (300 mm^2)
Max power*	500 *MW*
Max percentage power loss	2.07 %
Average power*	224*MW*
Average percentage power loss	0.93 %

* Transmitted within the farm

Appendix Figure 9: Cable structure case 4

Of the discussed cable structures, case 1 is decided as the favourable solution as the associated costs from cable acquisition and installation, combined with maximum loss costs based on an expected real wholesale value of €^{2013} 45 per *MWh* (European Commission 2012b) are expected to be lowest for this solution, shown in Digital Appendix 1. Additionally, this case is expected to be safest with regards to possible cable failures, as any potential failures could only lead to downtime for five turbines.

Choice of Export Cable

One central question when finding export cable costs comes is whether one or two cables are to be installed. Use of two cables reduces the expected farm downtime due to cable failures, as power could be distributed through one cable if the other were to fail, but also significantly increases capital costs from cable acquisition and installation. Additionally, use of two cables is expected to impact the preferred rating of the cable with regards to e.g. voltage, cross-sectional area etc.

When evaluating the rating and quantity of export cables to be deployed for our benchmark farms, the discounted additional cost associated with purchase and installation of two cables instead of one have been weighted against associated ohmic losses and downtime losses due to cable failure, and their quantified costs.

Capital costs have been found using benchmark acquisition costs presented in Appendix Table 8, while installation costs are evaluated as €^{2013} 590 000 per *km* for single cable installation, and €^{2013} 1 062 000 per *km* for double cable, double trench installation. Maximum ohmic losses costs are quantified through finding the dissipated losses from variables such as transferred power, voltage, cable length, resistivity and cross-sectional area, before assigning a real wholesale value of €^{2013} 45 per *MWh* to the losses (European Commission 2012b).

Expected downtimes are found from assumptions that the annual failure rate of subsea cables equals 0,1 failures per 100 *km* of cable (CIGRE 2009a), and that these on average take approximately two months to repair (CIGRE 2009b). For two cables, the probability for two failures occurring at once, leading to complete downtime of the park, is found through evaluating individual cable failure probabilities as independent probabilities.

The attached MS Excel LCOE model (Digital Appendix 1) estimates low case discounted costs of cable acquisition and installation, maximum ohmic losses and downtime losses to approximately €^{2013} 346 million for benchmark use of two 1200 mm^2, 150 kV HVDC extruded cables, and approximately €^{2013} 226 million for the use of one single 1500 mm^2, 320 kV extruded HVDC cable. Accordingly, one cable is chosen for our benchmark farms.

Export Cable Costs

Appendix Table 8 presents acquisition costs for HVDC power cables.

Appendix Table 8: Export cable (National Grid 2011)

Export Cable*	Low	Base	High
150 kV, 1200 mm^2	€ 236 000	€ 354 000	€ 472 000
150 kV, 1500 mm^2	€ 295 000	€ 384 000	€ 472 000
150 kV, 1800 mm^2	€ 354 000	€ 443 000	€ 531 000
150 kV, 2000 mm^2	€ 354 000	€ 472 000	€ 590 000
320 kV, 1200 mm^2	€ 354 000	€ 443 000	€ 531 000
320 kV, 1500 mm^2	€ 354 000	€ 443 000	€ 531 000
320 kV, 1800 mm^2	€ 354 000	€ 472 000	€ 590 000
320 kV, 2000 mm^2	€ 413 000	€ 531 000	€ 649 000
400 kV, 1500 mm^2	€ 413 000	€ 531 000	€ 649 000
400 kV, 1800 mm^2	€ 472 000	€ 561 000	€ 649 000
400 kV, 2000 mm^2	€ 472 000	€ 590 000	€ 708 000
400 kV, 2500 mm^2	€ 590 000	€ 708 000	€ 826 000
500 kV, 1500 mm^2	€ 472 000	€ 561 000	€ 649 000
500 kV, 1800 mm^2	€ 472 000	€ 590 000	€ 708 000
500 kV, 2000 mm^2	€ 472 000	€ 620 000	€ 767 000
500 kV, 2500 mm^2	€ 590 000	€ 738 000	€ 885 000

* 150 - 320 kV is HVDC Extruded Subsea Cable and 400 - 500 kV is Mass Impregnated Insulated Subsea Cable.

Appendix 8

Offshore Substation

A complete HVDC substation includes AC switchgear, transformers, converter electronics and filters. The specific components that will be required to increase the voltage prior to exporting the power to shore in best possible way, is highly farm specific and will not be discussed in this thesis. However, the main cost drivers for the substation are assumed to be the converter and the substation platform, while other components are assumed to relative low. The converter is assumed to be based on Voltage Source Converters (VSC) technology and the largest VSC system installed today is the BorWin2 platform with a rating of 800 *MW* (Siemens 2012b). Within the commissioning date of our proposed wind farm, the rating of a VSC system is assumed to exceed 1 000 *MW* (National Grid 2011), making this a maximum rating for one single substation. For wind farms with a total power rate beyond this rating, it is assumed that the farm needs more than one substation. Appendix Table 9 shows the assumed ratio between the farm size and number of substation needed.

Appendix Table 9: Ratio between the farm size and number of substation

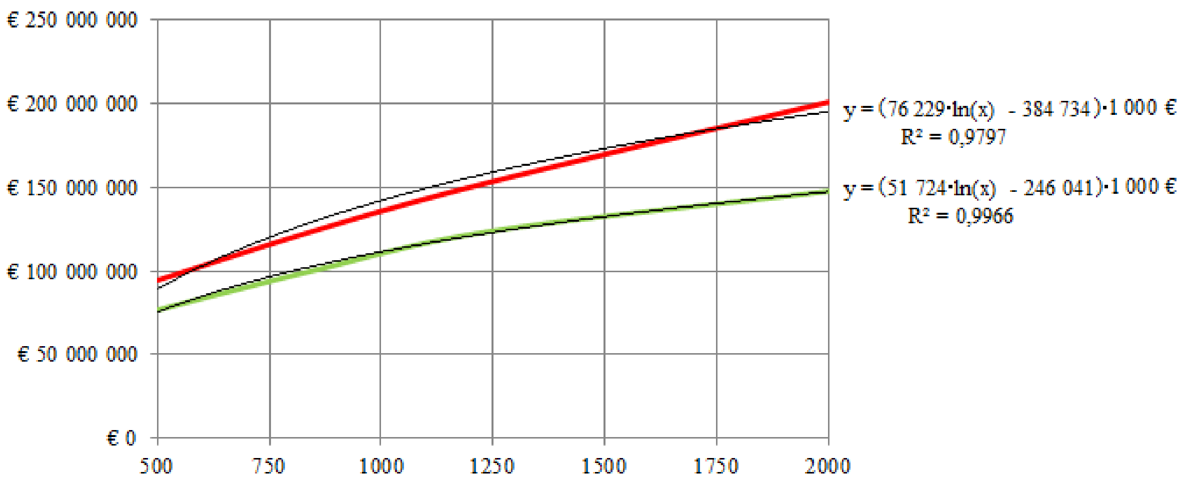
Number of turbines	Power rate	Number of substation	
		500 *MW* Substation	1 000 *MW* Substation
100	500 *MW*	1	
200	1 000 *MW*		1
300	1 500 *MW*	1	1
500	2 500 *MW*	1	2
1 000	5 000 *MW*		5

With increasing farm sizes, it is assumed that farms are composed of 100 wind turbine clusters, leading to assumptions that the inter-array cable consumption is proportional to farm size. Added number of clusters assigned to several substations indicate the presence of increasing lengths of export cable. However, logistical operations with regards to farm positioning, e.g. through making the maximum distance to the clusters our benchmark distance leads to assumptions that costs from further export cable laying negligible.

Appendix Table 10 shows estimated costs for a future VSC technology.

Appendix Table 10: Estimated costs for a Voltage Source Converters excl. platform (National Grid 2011). Numbers in €^{2013}

Specifications	Unit cost - Low	Unit cost - High
500 *MW*, 300 *kV*	€ 76 657 000	€ 94 347 000
850 *MW*, 320 *kV*	€ 100 244 000	€ 123 831 000
1250 *MW*, 500 *kV*	€ 123 831 000	€ 153 314 000
2000 *MW*, 500 *kV*	€ 147 417 000	€ 200 488 000



Appendix Figure 10: Estimated costs for a Voltage Source Converters excl. platform (National Grid 2011)

The price estimate presented in Appendix Table 10 seems to follow a logaritmic function, as shown in Appendix Figure 10. For a converter with rating of 500 *MW*, the costs is assumed to be €^{2013} 76.6 – 94.3 million. Based on the logoaritic function in Appendix Figure 10, the cost for a converter with rating of 500 *MW* is assumed to be €^{2013} 111.2 - 141.8 million.

To calculate the costs for a platform capable for a 500 *MW* VSC system, a linear relationship between the price estimates and the platform size is assumed, presented in Appendix Table 11.

Appendix Table 11:Offshore substation platform cost estimates (National Grid 2011)

Components	400 *MW*, ±300 *kV*, 3 500 *ton*		1 000 *MW*,±500 *kV*, 8 000 *ton*	
	Low	High	Low	High
Topside	€ 33 022 000	€ 38 918 000	€ 70 760 000	€ 94 347 000
Jacket	€ 9 435 000	€ 12 973 000	€ 23 587 000	€ 29 483 000
Installation	€ 18 869 000	€ 23 587 000	€ 31 842 000	€ 41 277 000
Total costs	€ 61 326 000	€ 75 478 000	€ 126 189 000	€ 165 107 000

Seeing the converter and the substation platform as the main cost drivers for a substation, total acquisition costs for 500 *MW* and 1000 *MW* bottom-fixed substations are presented in Appendix Table 12.

Appendix Table 12: Estimated total offshore substation costs

Components	500 *MW* bottom-fixed substation		1 000 *MW* bottom-fixed substation	
	Low	High	Low	High
VSC	€ 76 657 000	€ 94 347 000	€ 111 256 000	€ 141 837 000
Topside	€ 39 312 000	€ 48 156 000	€ 70 760 000	€ 94 347 000
Jacket	€ 11 794 000	€ 15 725 000	€ 23 587 000	€ 29 483 000
Installation	€ 21 031 000	€ 26 535 000	€ 31 842 000	€ 41 277 000
Total costs	€ 148 794 000	€ 184 763 000	€ 126 189 000	€ 165 107 000

Seeing as little information on floating substations exist, the offshore substation defined in this thesis is decided to be placed on a generic floater, so the substation floater concept is not influenced by changes in wind turbine floater concepts. It is assumed that the technology for a floating substation will exist when the floating wind industry is mature enough. It is conservatively assumed that locating the substation on a semi-submersible platform similar to the WindFloat concept is the most feasible solution, as semi-subs may be regarded the most stable floating substructure of the discussed concepts, minimising the risks of substation malfunction. Based on assumptions that the production costs of jackets and floaters are proportional to their carried load, production costs for semi-submersible platforms (Table 14) for floating 500 *MW* substructures are assumed to be roughly 236 % those of their bottom-fixed (Table 15) equivalents. Total installations costs for jacket-based wind turbines (Table 21) seem to be approximately 22 % more expensive than total costs for mooring system acquisition, mooring system installation and float-out installation of WindFloat wind turbines (Table 19, Table 25 and Table 26). Accordingly, total acquisition costs for 500 *MW* and 1000 *MW* floating substations are presented in Appendix Table 13.

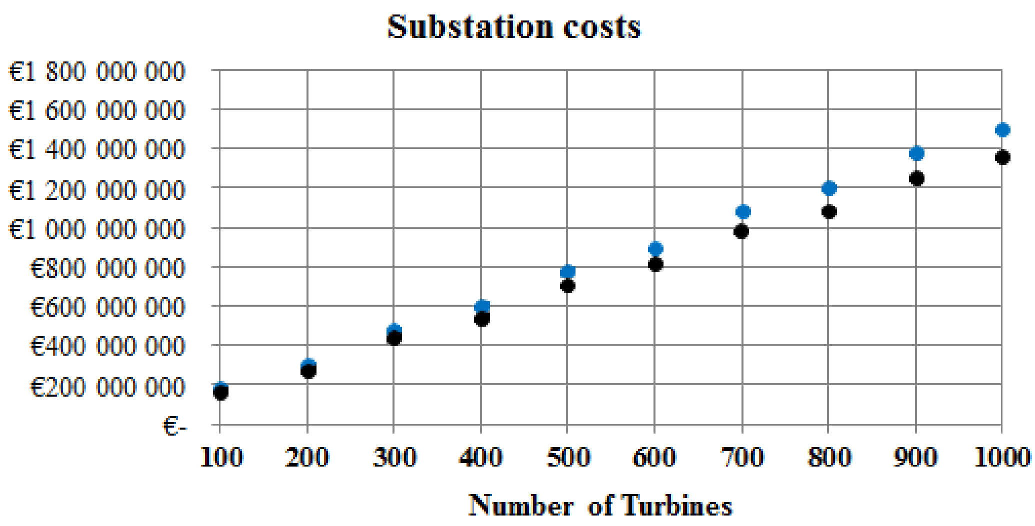
Appendix Table 13: Estimated total floating offshore substation costs

Components	500 *MW* floating substation		1 000 *MW* floating substation	
	Low	High	Low	High
VSC	€ 76 657 000	€ 94 347 000	€ 111 256 000	€ 141 837 000
Topside	€ 39 312 000	€ 48 156 000	€ 70 760 000	€ 94 347 000
Jacket	€ 27 816 000	€ 37 087 000	€ 55 630 000	€ 69 535 000
Installation	€ 16 411 000	€ 20 706 000	€ 24 847 000	€ 32 210 000
Total costs	€ 160 196 000	€ 200 296 000	€ 262 493 000	€ 337 929 000

It is assumed that the baseline price estimates for the bottom-fixed and floating substations is the average of the high and low estimates presented in Appendix Table 12 and Appendix Table 13. The ratio between the farm size and number of substation needed is presented in Appendix Table 9, which gives the total baseline costs of substation presented in Appendix Table 14 and Appendix Figure 11.

Appendix Table 14: Total estimated baseline costs for bottom-fixed and floating substations

Number of turbines	Power rate	Bottom-fixed substation	Floating substation
100	500 *MW*	€ 166 779 000	€ 180 247 000
200	1 000 *MW*	€ 272 196 000	€ 300 213 000
300	1 500 *MW*	€ 438 975 000	€ 480 460 000
500	2 500 *MW*	€ 711 171 000	€ 780 673 000
1 000	5 000 *MW*	€ 1 360 980 000	€ 1 501 065 000



Appendix Figure 11: Total substation cost distributions

Appendix 9

Installation Cost Examples, Floating Concepts

Here, examples of installation cost calculations for floating wind turbine concepts are shown, depending on installation strategy. Remaining cost calculations are presented in Digital Appendix 1.

Towing of Complete, Vertical Wind Turbines (Strategy 1)

Here, concept installation costs for vertical towing of wind turbines assembled near shore (Figure 70) will be evaluated, depending on turbine lift categories.

This installation strategy is based on assumptions that floaters are launched from quay, evaluated as one quayside lift. Two tug boats transport the floater near a crane barge, where the tug boats up-end the floater. Turbine components are lifted from a quayside mobile crane onto a barge towed by a tug boat, which transports the carrying barge to the near-shore crane barge. A total of two tug boats assist the crane barge during lifting operations. The tower may either be lifted by the crane barge, or preassembled onto the floater during the production process. After lifting operations are completed, the wind turbine is towed to offshore site and connected to mooring system using an AHTS and two tug boats.

One example of installation cost calculations are shown in Appendix Table 15, where near-shore installation costs of Hywind wind turbines through three lifting operations are shown:

Appendix Table 15: Installation cost calculation example: Hywind, three turbine lifts

Vessel type	Operation	Value	Duration	Unit cost	OW	Total cost
Lifting operations						
Quayside crane	Quayside lifts	4.00	0.08	€ 6 000	75 %	€ 2 667
Crane barge	Rigging	1.00	0.08	€ 55 000	75 %	€ 6 111
	Ballast		1.00		60 %	€ 91 667
	3 near-shore lifts		0.63		72 %	€ 47 676
	Personnel usage	30.0	0.63	€ 370	72 %	€ 9 622
Loading, Assistance and Transportation						
Tug boats	Loading	2.00	0.33	€ 17 000	75 %	€ 15 111
	Up-ending		0.50		60 %	€ 22 667
	Assistance		0.63		72 %	€ 29 473
	Transportation		1.80		54 %	€ 113 324
	Mooring		0.75		55 %	€ 46 364
AHTS	Transportation	1.00	1.80	€ 91 000	54 %	€ 303 309
	Mooring		0.75		55 %	€ 124 091
Total installation cost per wind turbine						**€ 812 081**

Appendix Table 16 summarises concept installation costs for complete, near-shore assembly, depending on turbine lift strategy. These costs also include assigned mobilisation lump sums.

Appendix Table 16: Concept installation costs for towing of complete wind turbines. All values in €^{2013}

Strategy	TLB B/TLB X3	Hywind	WindFloat	SWAY
1A	€ 859 848	€ 878 275	€ 736 319	€ 746 783[1]
1B	€ 817 737	€ 836 164	€ 699 874	€ 704 672
1C	€ 798 585	€ 817 011	€ 680 722	€ 685 519[1]
1D	€ 767 969	€ 786 396	€ 644 440	€ 654 904
1E	€ 803 657	€ 822 083	€ 680 127	€ 690 591[1]

1) Debatable due to floater/tower integration of SWAY concept

As indicated in the table, a lift strategy of two lifts; nacelle and preassembled rotor positioned onto a preassembled floater and tower configuration is preferred for all concepts when evaluating near-shore installation. This is mainly due to the fact that this lift strategy reduces lift time relative to individual blade lifts significantly, while operational windows still exceed those for a single lift of the turbine. The WindFloat and SWAY concepts seem most reasonable to tow, due to their stability.

Towing of Floater or Floater and Tower Configuration (Strategy 2)

Here, concept installation costs for towing of floaters or preassembled floater- and tower configurations, as seen in Figure 72 and Figure 73, are evaluated.

This installation strategy is based on the assumption that floaters or floater- and tower configurations are launched and then towed to site, up-ended and moored using an AHTS assisted by two tug boats. At site, a crane vessel handles ballast and remaining lift operations. The crane vessel is assisted by both an AHTS and tug boats, and also a PSV responsible for transport of turbine components.

Appendix Table 17 summarises concept installation costs for towing of floater and tower configurations, depending on turbine lift strategy, including mobilisation costs:

Appendix Table 17: Concept installation costs for towing floaters or floater and tower configurations. All values in €^{2013}

Strategy	TLB B/TLB X3	Hywind	WindFloat	SWAY
2A	€ 2 082 187	€ 2 825 295	€ 2 737 861	€ 2 729 947[1]
2B	€ 1 952 078	€ 2 701 793	€ 2 555 177	€ 2 585 035
2C	€ 1 585 020	€ 2 328 128	€ 2 240 693	€ 2 232 780[1]
2D	€ 1 307 908	€ 2 040 038	€ 1 943 056	€ 1 924 841
2E	€ 1 735 871	€ 2 478 979	€ 2 391 544	€ 2 383 631[1]

1) Debatable due to floater/tower integration of SWAY concept

It becomes apparent that employment of a highly expensive offshore crane vessel, where operational windows are smaller, severely adds to the total installation costs. However, lifting a nacelle and rotor onto a preassembled floater and tower configuration seems to be the preferred solution regardless of whether turbine installation operations are to be done near shore or offshore. The TLB concepts seem to be significantly more reasonable than the other concepts for at-site installation of components due to their low weight leading to relatively high transit speeds.

From the estimated installation costs presented in Appendix Table 16 and Appendix Table 17, it seems apparent that the favourable installation strategy for all discussed concepts is strategy 1D, where the tower is attached to the floating substructure as a part of the production process, before the turbine nacelle and preassembled rotor are attached to the tower near shore using a crane barge, in order to not have to rely on a severely expensive crane vessel able to perform offshore lifts. The total lift time for this installation method is expected to be significantly shorter than other methods, and even though the operational window only places third of the five evaluated lift strategies, the deduction in lift time counteracts the fact that other lift strategies have more profitable operational window estimates. By assumptions that floaters and towers may be produced as integrated components, and that up-ending is expected to be virtually equal for floaters and floater and tower configurations, reductions of one turbine lift both quayside and near shore makes strategy 1D preferable to strategy 1C.

One example of installation cost calculations are shown in Appendix Table 18, where installation costs of WindFloat wind turbines through four offshore lifting operations onto an integrated floater and tower configuration are shown.

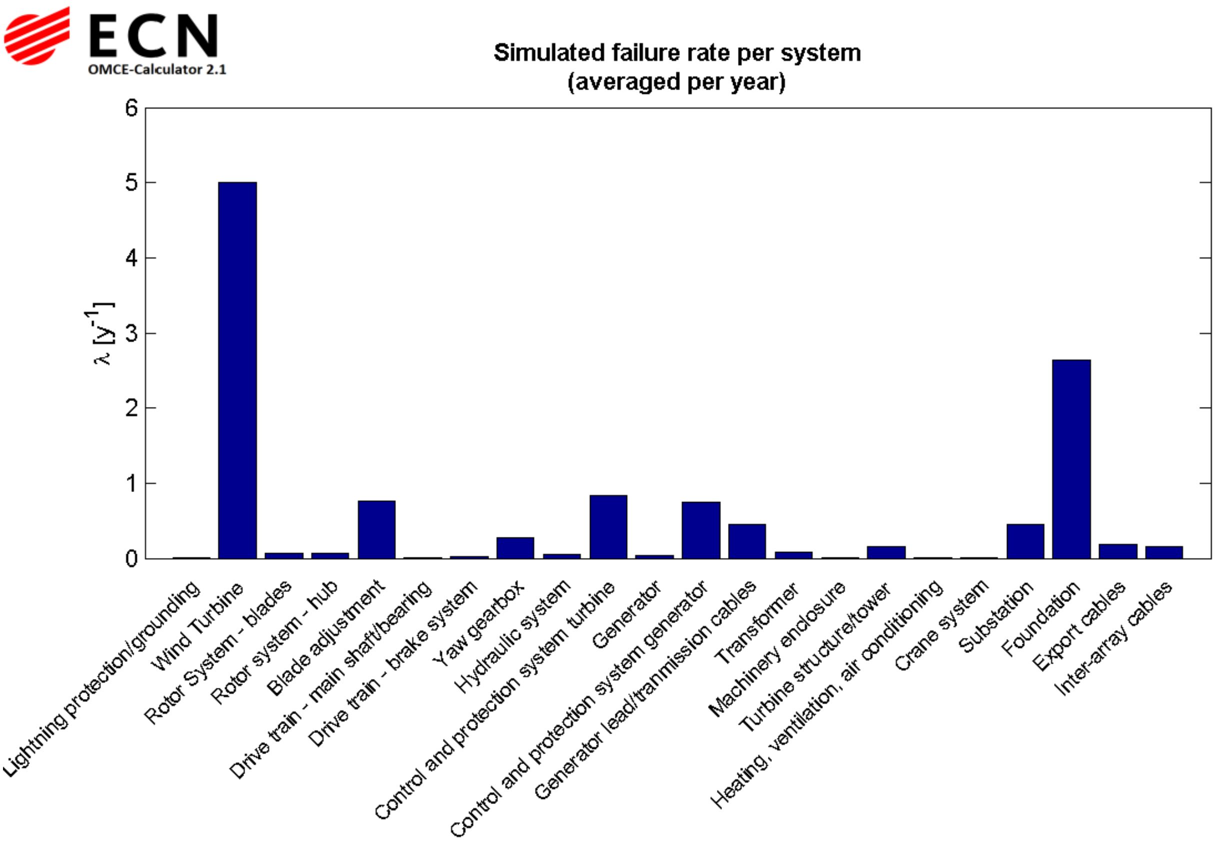
Appendix Table 18: Installation cost calculation example: WindFloat, four turbine lifts

Vessel type	Operation	Value	Duration	Unit cost	OW	Total cost
Lifting operations						
Quayside crane	Quayside lifts	5.00	0.08	€ 6 000	75 %	€ 3 333
Crane vessel	Rigging	1.00	0.17	€ 531 000	65 %	€ 136 154
	Ballast		1.00		60 %	€ 885 000
	4 offshore lifts		0.67		46 %	€ 773 592
	Personnel usage	30.0	0.67	€ 370	46 %	€ 16 171
Loading, Assistance and Transportation						
Tug boats	Transportation	1.00	1.05	€ 17 000	71 %	€ 50 560
	Up-ending	2.00	0.00		60 %	€ 0
	Mooring		1.00		55 %	€ 61 818
	Assistance		0.67		46 %	€ 49 533
AHTS	Transportation	0.50	1.05	€ 91 000	71 %	€ 135 323
	Up-ending	1.00	0.00		60 %	€ 0
	Mooring		1.00		55 %	€ 165 455
	Assistance		0.67		46 %	€ 132 574
PSV	Loading	1.00	0.33	€ 46 000	75 %	€ 20 444
	Transportation	0.33	0.50		70 %	€ 32 855
	Assistance	1.00	0.67		46 %	€ 67 015
Total installation cost per wind turbine						**€ 2 529 827**

Appendix 10

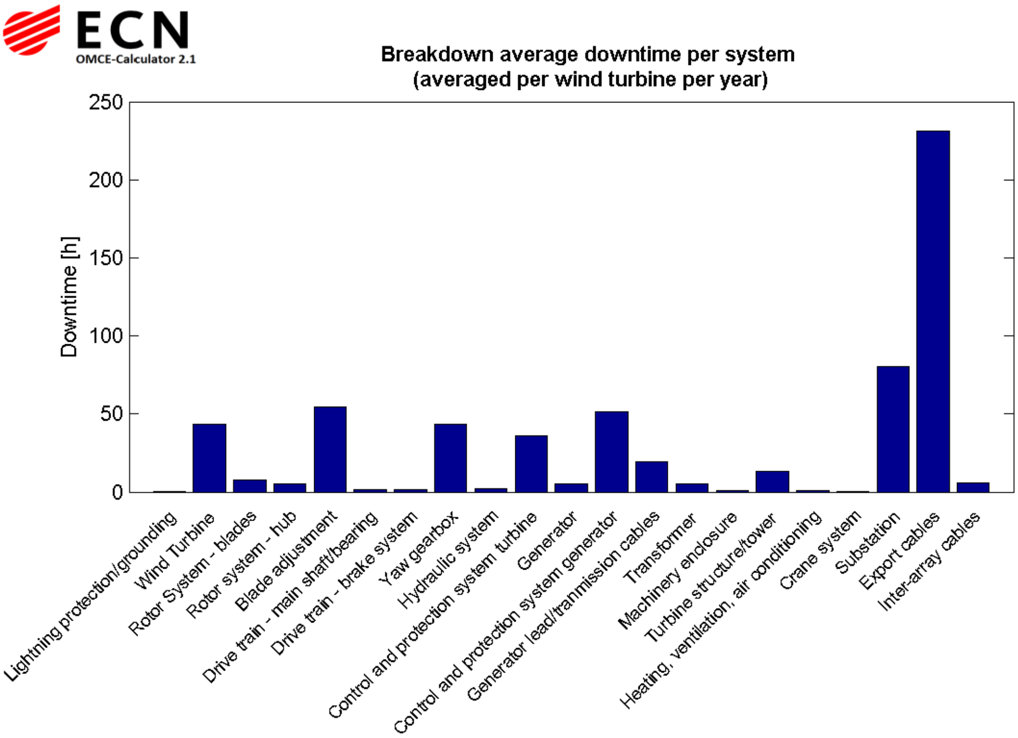
Operation and Maintenance Costs

Here, key findings on the O&M costs found through using the OMCE-Calculator are presented, based on simulations of benchmark floating wind farms. Additionally, simulations and assumptions associated with increasing offshore distances and farm sizes are presented. Values from all relevant data are presented in Digital Appendix 1.



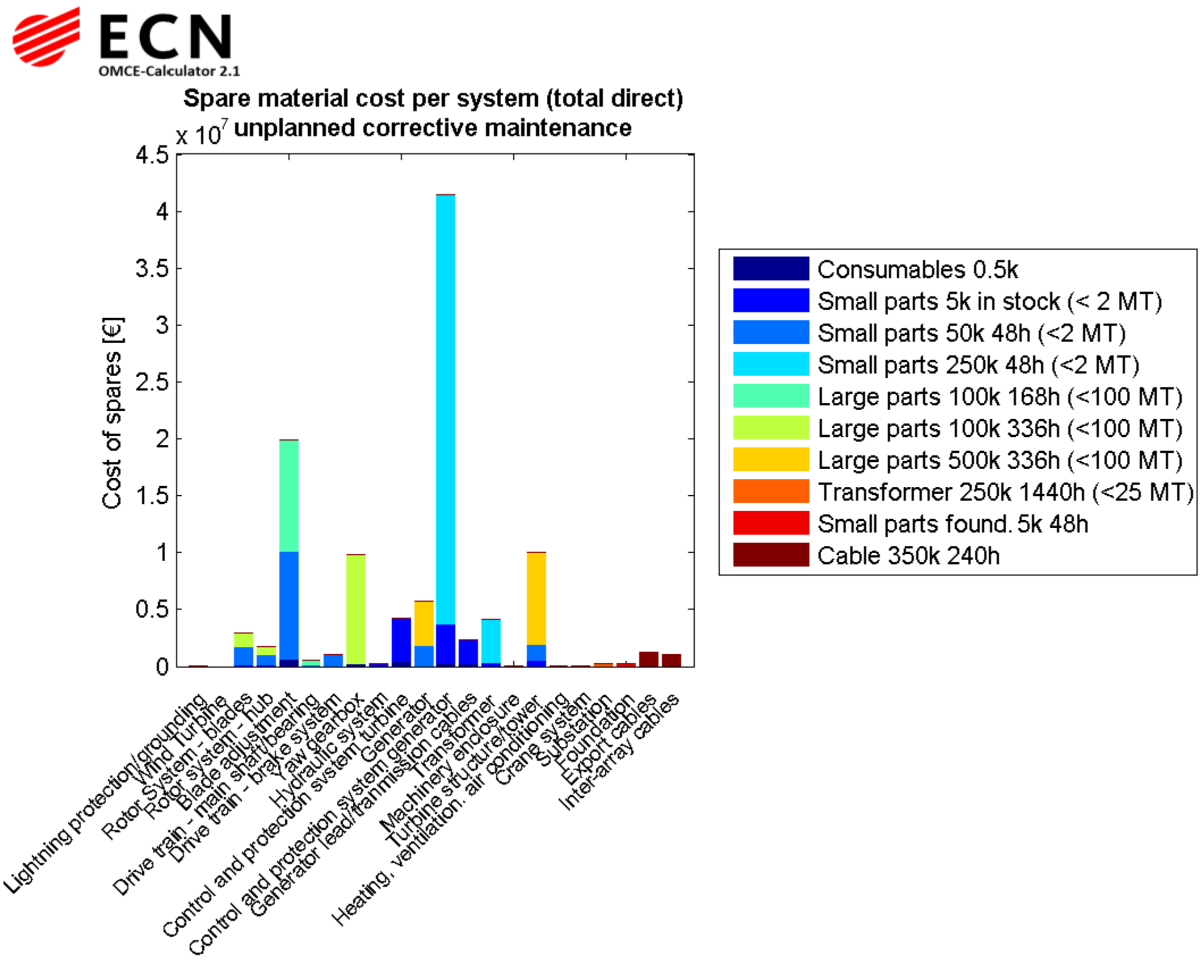
Appendix Figure 12: Simulated average failure rate per component

Appendix Figure 12 illuminates the simulated average failure rate of different component systems of the wind farms. The Wind Turbine category is understood as failures occurring to the wind turbine not directly applicable to the other component systems. As indicated, generic wind turbine failures seem to be the most common failures, with foundation failures coming in second. Broken down on a more specified level, the dominant wind turbine failures are ones coming from blade adjustment problems and control and protection systems for generators and turbines.



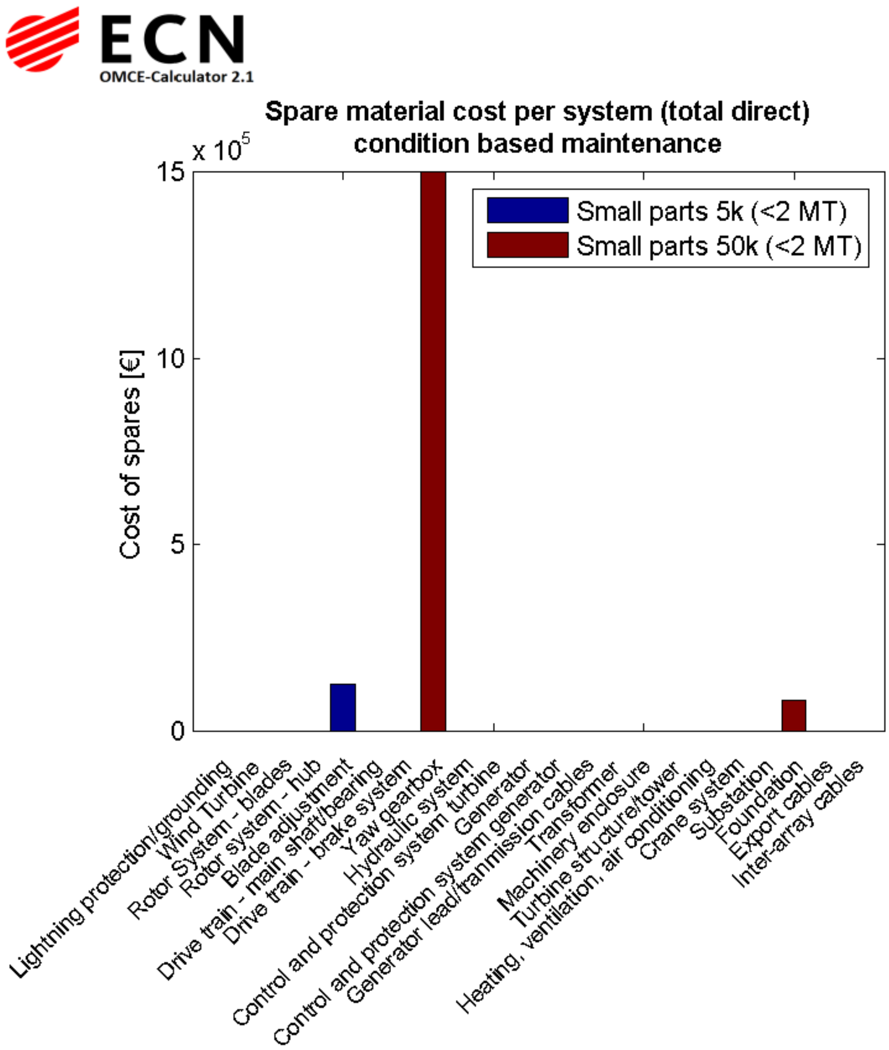
Appendix Figure 13: Average downtime breakdown

Appendix Figure 13 shows the average downtime contribution for components. The figure suggests that failures on export cables and substations are the main contributors to farm downtime, expected to be because such failures are assumed to lead to complete farm downtime. Of the turbine components, it seems failures at control and protection system generator, yaw gearbox and blade adjustment systems are the main contributors to downtime, consistent with failure rates presented in Appendix Figure 12.



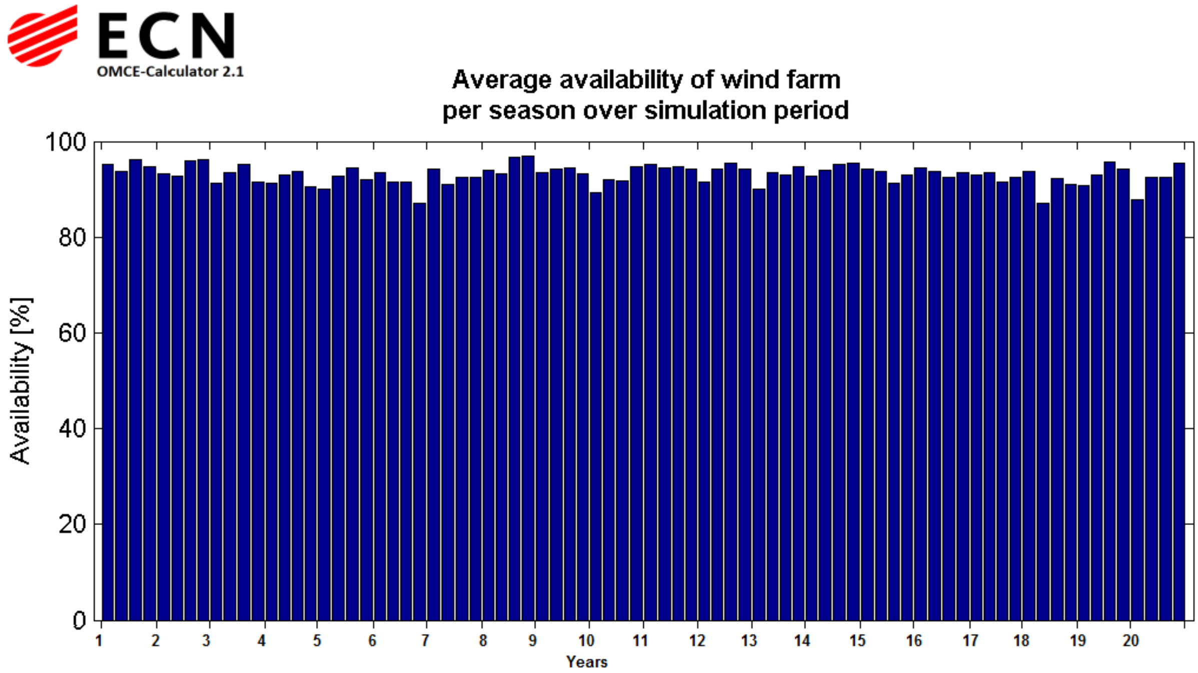
Appendix Figure 14: Spare material costs over simulation period

Appendix Figure 14 shows the total spare part costs assigned to different farm components, distributed over average spare part cost, weight and lead time. The figure suggests a continued trend from Appendix Figure 12 and Appendix Figure 13, where components experiencing the most failures leading to the biggest downtimes are expected to require the largest number of spare parts. Even though export and substation cable failures are expected to contribute most to farm downtimes, repair actions are expected to be relatively infrequent based on spare part costs.



Appendix Figure 15: Spare part cost breakdown - condition-based maintenance

Appendix Figure 15 shows that for condition-based maintenance, almost all spare part costs come from yaw gearbox maintenance operations.



Appendix Figure 16: Average availability

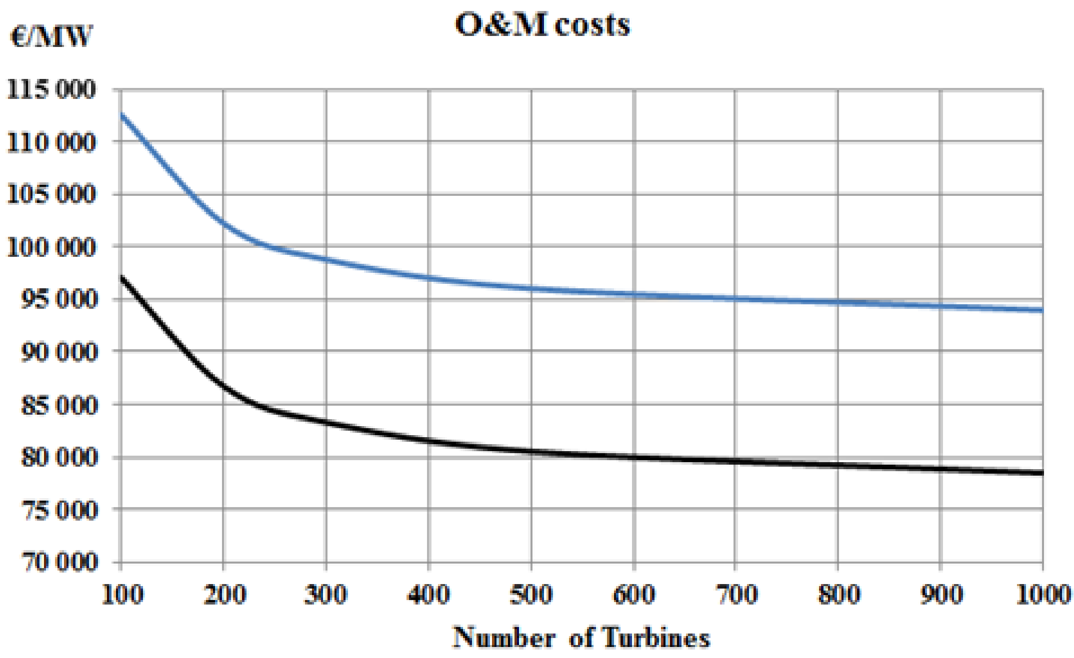
Appendix Figure 16 shows the average availability of the wind farm on a season basis. As indicated, availabilities are simulated to be fairly consistent, but the figure indicates season of low availability due to high simulated maintenance efforts.

Cost Driver Changes

With increasing farm sizes, most aspects related to O&M costs are assumed proportional to farm size increments. These aspects include costs related to permanently employed technicians and all spare part and equipment costs associated with O&M, except mother vessels.

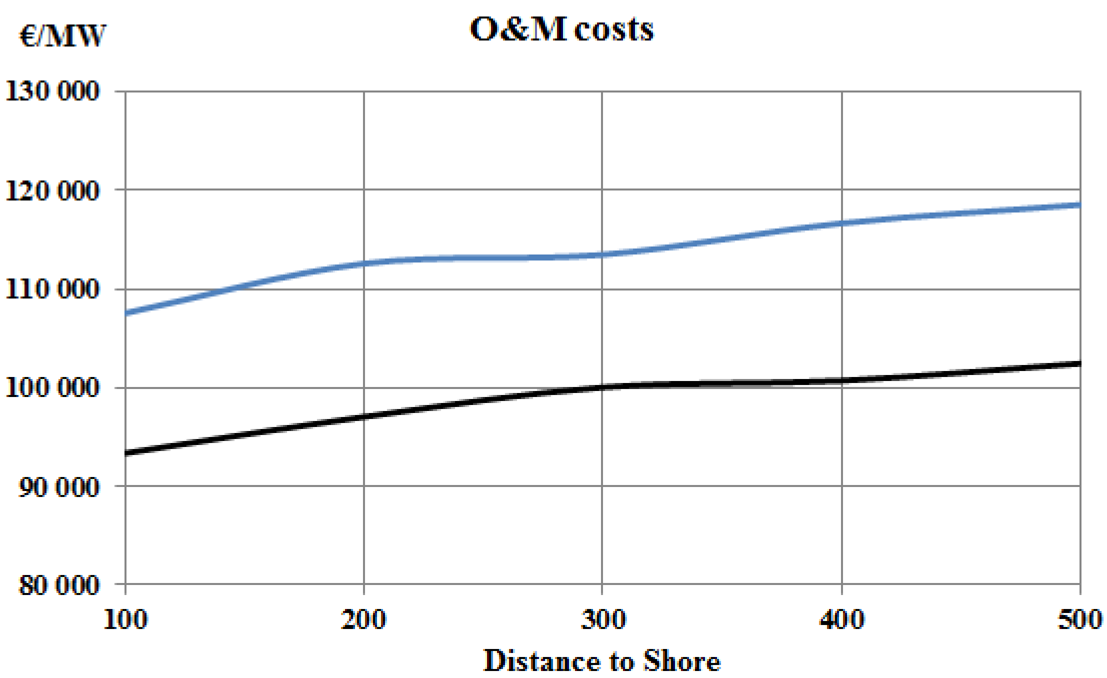
With increasing farm sizes, it is expected that mother vessels may become slightly larger and more expensive, before farms at one point become so large that more than one vessel is best deployed to maintain a high percentage use of employed technicians. Desired number of vessels and their respective sizes could then be subjected for extensive simulations to find an optimal balance between mother vessel costs and costs associated with better access to the wind turbines. Accordingly, a step-by-step increase of total mother vessel costs reminiscent of the developments for substation costs shown in Appendix Figure 11 could be assumed. However, for this thesis, a simplified approach is assumed, with increases of 50 % of the benchmark farm mother vessel costs for each 100 additional wind turbines.

A similar approach is used in estimating costs related to onshore personnel, while port costs through simplifications are assumed to be constant. When all costs are summarised and distributed over total wind farm size, the per *MW* O&M costs are illustrated in Appendix Figure 17. Note that these costs do not include operation phase insurance costs, assumed to be proportional to farm size.



Appendix Figure 17: Per MW O&M costs with increasing farm size

With offshore distances increasing, costs are merely affected by increased travel times for vessels, simulated by changing input parameters for the OMCE-Calculator. Cost developments are presented in Appendix Figure 18.



Appendix Figure 18: Per MW O&M costs with increasing offshore distances

O&M Costs Associated with Towing of Wind Turbines to Shore

O&M costs related to towing the wind turbines to shore are conservatively estimated by finding time spent for detaching and towing the floating wind turbine concept with the most demanding combined attaching and towing time consumption, being the TLB concepts given our thesis assumptions presented in section 3.3.3, as this concept utilises the highest number of mooring lines.

The entire operation may be regarded as follows:

One AHTS and two tug boats are used to reverse the hook-up operation of the wind turbine. The turbine is then either transferred to an existing shore side infrastructure or to calmer water where it is possible to do maintenance operation with a crane barge. This provides the opportunity for significant cost and risk reduction relative to unscheduled maintenance at times with high demand and cost of crane vessels.

To calculate the costs for towing the wind turbine back to shore for bigger unplanned turbine maintenance, some simplification and assumptions are made:

- One AHTS and two tug boats will assist throughout the entire maintenance operation.
- The hook-up and reverse hook-up is assumed to be the same and based on the average connection time including operational window for the floating concepts in the installation phase.
- The transit time back and forth is based on the transit time including operational window that the AHTS uses for towing the complete wind turbine in the installation phase.
- One crane barge will be used for the repair or replacement operation. It is assumed that this will take 24 hours including rigging, with an operational window of 70 %.

With assumptions presented in section 3.3.3, costs related to each operation are presented in Digital Appendix 1 and Appendix Table 19.

Appendix Table 19: Per trip costs associated with towing wind turbines to shore for maintenance

Operation	OW	Value
Detachment and attachment of mooring lines	55 %	3 days
Towing to and from shore (days)	45 %	2 days
Crane barge operation (days)	70 %	1 day
AHTS costs	-	$€^{2013}$ 1 031 000
Tug boat costs	-	$€^{2013}$ 385 000
Crane barge costs	-	$€^{2013}$ 79 000
Mobilisation costs	-	$€^{2013}$ 493 000
Total cost of each operation	-	$€^{2013}$ 1 987 000

These costs are used as inputs for the OMCE-Calculator, leading to O&M costs presented in Appendix Table 20.

Appendix Table 20: Annual O&M costs, towing wind turbines to shore

Number of maintenance events per year	Low	Base	High
Unplanned corrective	805	855	890
Condition based	4	4	4
Calendar based	120	120	120

Downtime per year	Low	Base	High
Unplanned corrective (h)	36 870	68 540	109 231
Condition based (h)	55	55	55
Calendar based (h)	3 360	3 360	3 360
Total (h)	**40 285**	**71 955**	**112 646**
Availability (time)	**95.4%**	**91.8%**	**87.2%**
Loss of production per year	**104 757**	**189 189**	**313 703**

Cost of repair per year	Low	Base	High
Material costs			
Unplanned corrective	€ 4 821 900	€ 5 260 495	€ 5 592 250
Condition based	€ 131 250	€ 131 250	€ 131 250
Calendar based	€ 1 600 000	€ 1 600 000	€ 1 600 000
Labour costs			
Unplanned corrective	€ 4 766 000	€ 4 766 000	€ 4 766 000
Condition based	€ 32 190	€ 32 126	€ 32 074
Calendar based	€ 0	€ 0	€ 0
Equipment costs			
Unplanned corrective	€ 40 952 822	€ 44 222 300	€ 47 785 742
Condition based	€ 1 533 323	€ 1 533 340	€ 1 533 403
Calendar based	€ 7 000	€ 7 259	€ 7 815
Total costs of repair per year	**€ 53 844 484**	**€ 57 552 770**	**€ 61 448 534**

Further, results from simulations with crane vessel day rates at €^{2013} 531 000 and from simulations without employments of mother vessels are presented in Appendix Table 21 and Appendix Table 22. Please note that for Appendix Table 22, three specialised vessels are simulated utilised instead of two, to increase accessibility.

Appendix Table 21: Annual O&M costs, expensive crane vessels

Number of maintenance events per year	**Low**	**Base**	**High**
Unplanned corrective	826	872	912
Condition based	4	4	4
Calendar based	120	120	120

Downtime per year	**Low**	**Base**	**High**
Unplanned corrective (h)	28 010	51 798	88 197
Condition based (h)	55	55	55
Calendar based (h)	3 360	3 360	3 360
Total (h)	**31 425**	**55 213**	**91 612**
Availability (time)	**96.4%**	**93.7%**	**89.6%**
Loss of production per year	**84 121**	**146 760**	**240 632**

Cost of repair per year	**Low**	**Base**	**High**
Material costs			
Unplanned corrective	€ 4 957 175	€ 5 353 363	€ 5 739 225
Condition based	€ 131 250	€ 131 250	€ 131 250
Calendar based	€ 1 600 000	€ 1 600 000	€ 1 600 000
Labour costs			
Unplanned corrective	€ 4 766 000	€ 4 766 000	€ 4 766 000
Condition based	€ 32 200	€ 32 171	€ 32 127
Calendar based	€ 0	€ 0	€ 0
Equipment costs			
Unplanned corrective	€ 53 680 692	€ 58 712 071	€ 64 252 912
Condition based	€ 1 556 160	€ 1 556 184	€ 1 556 240
Calendar based	€ 0	€ 0	€ 0
Total costs of repair per year	**€ 66 723 477**	**€ 72 151 039**	**€ 78 077 754**

Appendix Table 22:Annual O&M costs, no mother vessel (technician transport to and from shore)

Number of maintenance events per year	**Low**	**Base**	**High**
Unplanned corrective	824	848	870
Condition based	4	4	4
Calendar based	115	116	117

Downtime per year	**Low**	**Base**	**High**
Unplanned corrective (h)	57 290	74 714	97 517
Condition based (h)	149	149	149
Calendar based (h)	3 183	3 206	3 243
Total (h)	**60 623**	**78 069**	**100 909**
Availability (time)	**93.1%**	**91.1%**	**88.5%**
Loss of production per year	**165 360**	**211 615**	**273 086**

Cost of repair per year	**Low**	**Base**	**High**
Material costs			
Unplanned corrective	€ 4 861 375	€ 5 254 488	€ 5 827 225
Condition based	€ 131 250	€ 131 250	€ 131 250
Calendar based	€ 1 496 500	€ 1 510 620	€ 1 530 500
Labour costs			
Unplanned corrective	€ 4 766 000	€ 4 766 000	€ 4 766 000
Condition based	€ 32 560	€ 32 560	€ 32 560
Calendar based	€ 0	€ 0	€ 0
Equipment costs			
Unplanned corrective	€ 39 286 175	€ 42 438 554	€ 45 145 913
Condition based	€ 1 431 758	€ 1 432 127	€ 1 432 350
Calendar based	€ 0	€ 0	€ 0
Total costs of repair per year	**€ 52 005 618**	**€ 55 565 598**	**€ 58 865 798**

Note that costs associated with port activities are not changed when disregarding mother vessels. With increasing port activities, these costs may be expected to increase. However, as the evaluated strategy is not implemented in the thesis, port costs are not discussed further, leaving Appendix Table 22 a somewhat liberal O&M cost estimate.

Appendix 11

Operation Phase Insurance Properties

Appendix Table 23: Operations phase insurance (PricewaterhouseCoopers 2012)

Product	Triggering events	Scope	Status for offshore wind
Operating All Risks/ Physical Damage	Sudden and unforeseen physical loss or physical damage to the plant / assets during the operational phase of a project.	"All risks" package.	Increasingly, insurers require projects to demonstrate what loss control measures are in place to minimise losses from high wind, freak wave conditions, fire and lightning and vessel collision
Machinery Breakdown	Sudden and accidental mechanical and electrical breakdown necessitating repair or replacement.	Various levels of cover for defects in material, design construction, erection or assembly are available subject to the experience of the equipment, new WTG's with no commercial operating experience are unlikely to get full cover.	Cover for design risk is difficult to achieve as the technology tends to evolve rapidly, denying insurers sufficient data that demonstrates a low design risk
Business Interruption	Sudden and unforeseen physical loss or physical damage to the plant/assets during the operational phase of a project causing an interruption.	Loss of revenue as a result of an interruption in business caused by perils insured under the Operating All Risks policy.	Loss of a single turbine would lead to an insignificant business interruption claim, while any loss to the export cable or transformer could lead to a significant interruption to overall output. The premium rates for offshore business interruption therefore vary significantly depending on the design of the project. Repair times on cables are extensive and offshore transformers have lead times of at least 18 months to replace.
General/Third-Party Liability	Liability imposed by law, and/or Express Contractual Liability, for Bodily Injury or Property Damage.	This is coverage for the Works and the Project Liabilities. Coverage for hull and charterers liability is an additional purchase and is widely available in the Marine market.	Likely to be inherent in the majority of insurance packages.

Appendix 12

Cost Reduction Potentials

As with onshore wind, significant cost reductions for offshore wind are expected as performance improves and the industry matures. Such reductions could be achieved through a combination of technological and supply chain developments, scaling, learning, and standardisation effects. (Scottish Enterprise 2011) indicate that many of these cost reduction potential could be realised through benefiting from experiences from the existing oil and gas industry, and it is estimated that oil and gas expertise could reduce the CAPEX and OPEX costs for offshore wind energy with approximately 13.5 % and 15 %, respectively. These estimations match cost reduction potentials estimated by Carbon trust, as shown in Appendix Table 24.

Appendix Table 24: Cost reduction opportunities and implied learning rates (Delay & Jennings 2008).

Cost component	Technology developments	Economies of scale	Low	Mid	High
Turbine	● Incremental improvements e.g. blade design, alternative materials, more efficient generators ● Longer design life	● Upscaling and improved design – Larger and fewer turbines per offshore wind farm ● Standardisation	**10 %**	**15 %**	**15 %**
Substructure	● Decreased mass per *MW* ● New materials e.g. pre-stressed concrete ● Longer design life ● Not over-engineered	● High volume manufacture techniques ● Standardising	**5 %**	**10 %**	**15 %**
Grid Connection	● Lower transmission losses ● Improved generation over variable wind speeds	● Offshore grid connection shared across wind farms ● One HVDC converter per wind farm	**5 %**	**10 %**	**10 %**
Installation	● Faster, high volume installation techniques ● Wind turbines and foundations designed-for-installation	● Equipment standardisation ● Learning by doing ● Optimisation of ship use	**10 %**	**15 %**	**20 %**
O&M	● Remote and sonar condition monitoring ● All-weather access technologies	● Manned offshore O&M facilities ● Spare parts based on-site	**10 %**	**15 %**	**15 %**

For this thesis, mid-level cost reduction potentials for all categories in Appendix Table 24 are employed for LCOE sensitivity estimations.