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A regulatory and techno-economic analysis of developing an offshore wind farm at Sørlige Nordsjø II

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Master Renewable Energy

Preface

This master thesis marks the end of my master's program in renewable energy at NMBU. Written during the fall semester of 2020, the work has been very challenging due to the Corona virus pandemic. Luckily, digital tools such as Teams and Zoom have been helpful in interviewing relevant people and gathering information.

I would like to thank my supervisor Torjus Bolkesjø for providing me with feedback and ideas.

Considerable time has been spent on learning the software tool WindPRO, and I am grateful for the student access to this valuable tool. I would also like to thank the following people for providing me guidance, information, and data:

- Ann Myhrer Østenby & Jon Krogsvold at NVE.
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- Per Møller at WindPRO.
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- Daniel Willoch at Norwea
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- Frode Oplenskedal at Conoco Phillips

Finally, I would like to thank my family and friends for providing me with motivation and support along the way.

Oslo, 15 December 2020

Alexander Wang

Abstract

The European Commission recently presented a strategy proposal to increase Europe's offshore wind capacity to 60GW by 2030 and to 300GW by 2050. Along with strong wind resources, Norway has a tremendous opportunity to utilize its vast offshore oil and gas experience to the development of offshore wind. This transformation would enable a potential value creation of up to NOK 117 billion while simultaneously contributing to reduce greenhouse gas emission (Winje et al., 2019). Consequently, OED opened the Norwegian offshore areas Utsira Nord and Sørlige Nordsjø II for the development of a domestic offshore wind market (Olje-og-Energidepartementet, 2020). This master thesis investigates the techno-economic and regulatory feasibility of developing a 550MW offshore wind farm in the area Sørlige Nordsjø II. Such feasibility studies for a specific offshore wind farm in Norway is lacking in academia and hence the author intends to fill this gap.

The regulatory framework for offshore wind development in Norway is laid out in the Ocean Energy Law and the Ocean Energy Act. Other sector relevant laws and authorities are also required to be considered when developing offshore wind at Sørlige Nordsjø II. There is still uncertainty surrounding the licensing process and export cables which needs to be addressed. OED plans to release a guideline in spring 2021 which needs to clarify these regulatory issues.

Although in harsh sea conditions with water depths between 60-70m, it was found to be technically feasible to use four-legged jacket bottom-fixed foundation. The foundation is optimal for the seabed in the area which is characterized by sand and clay. Covering an area of 44 km^2, the 550MW wind farm is connected via 66kv array cables between 55 Siemens Gamesa SG 11-193 DD Flex turbines, each with a rated capacity of 11MW. Along with the wind data provided by Stormgeo, the offshore wind farm was simulated in WindPRO and was used to calculate a net AEP of 2.5 TWh.

The economic feasibility of the 550MW was assessed in three scenarios. Scenario 1, 2, and 3 is solely transmitting and selling the electricity to Norway, Germany, or U.K, respectively. Scenario 1 resulted in a positive NPV to equity after taxes of NOK 261,885,405. Scenario 2 resulted in a positive NPV to equity after taxes of NOK 2,497,911,190. Finally, scenario 3 resulted in a positive NPV to equity after taxes of NOK 4,303,294,971. All three scenarios were therefore economically feasible. That said, scenario 3 is the recommended option for the offshore wind farm due to the comparatively greater potential NPV and IRR. Last, LCOE was calculated at 0.52 NOK/kWh, which is in line with expected LCOE for bottom-fixed projects.

Table of Contents

Contents

List of figures

List of tables

1. Introduction

Through the Paris Climate Agreement, several countries worldwide have committed themselves to limit global warming to a 2-degree rise, preferable to below 1.5 degrees. In order to reach this limit, the world economy needs to rapidly transition from a high-carbon to a low-carbon energy society. The EU has taken the right step towards this transition by committing to reach an EU-wide policy of 32% renewable share in the final energy consumption by 2030, which is a monumental task when considering the current share of 18% (Eurostat, 2020). Furthermore, the proposed European Green Deal aims to make Europe climate neutral by 2050 through a series of ambitious policy initiatives and binding legal commitments. The case for this growth strategy is further strengthened by the need to boost the sluggish European economy following the Covid-19 pandemic crisis. In order to reach these climate and renewable energy targets, the EU has proposed to dramatically increase the share of offshore wind in the future European energy mix. The European Commission estimated a required installed capacity between 240 and 450GW of offshore wind power by 2050, which is a big jump from the current 23GW (Wind Europe, 2019b). This trend is echoed by IEA, who adds that offshore wind has the potential to becomes the number one source of electricity generation in Europe by 2042 (IEA, 2019a). As recently as 19th November 2020, the European Commission (2020) presented a strategy proposal to increase Europe's offshore wind capacity to 60GW by 2030 and to 300GW by 2050. How big of a share offshore wind will have in the future energy mix is yet to be determined. However, the industry will most certainly be a contributor to the rising share of renewable energy, and thus the market potential is significant.

1.1 Background

As part of the EEA and EU ETS, Norway faces both challenges and opportunities as a result of increasing integration into EU climate politics. One such challenge includes the need for Norway's oil and gas supply chain to adapt to a new energy environment in which the economy transforms away from oil & gas dependency. In addition to low oil prices, the oil & gas industry is facing a sustained decline in activity for years ahead as Europe and much of the developed countries continue to decarbonize. However, Norway has a tremendous opportunity to transform this industry into a growth machine within the offshore wind industry when considering its vast domestic wind resources and competence in deep-water projects. According to IEA, about 40% of the oil and gas supply value chain coincides with the offshore wind value chain (IEA, 2019a). By developing an early domestic market for deep-water offshore wind, Norway has the potential to gain a competitive advantage through technology learning when competing for global deep-water offshore wind projects. The potential value creation for the Norwegian offshore industry is significant, with Menon Economics assessing this to be as high as NOK 117 billion (Winje et al., 2019).

In response to this potential, offshore industry actors have pressured the Norwegian government for the past years to develop a home market for offshore wind (OW). On June 12th, 2020, an important milestone was met when Tina Bru, the acting Minister of Petroleum and Energy, announced the opening of two areas for offshore wind production on the Norwegian continental shelf: Sørlige Nordsjø II and Utsira Nord. In addition, the government laid out the playing rules for OW development in the Ocean Energy Regulation (Havenergiforskriften) which will come into force on January 1st, 2021. The Ocean Energy Regulation will allow developers to apply for a license for large-scale OW projects from January 1st, 2021 (Olje-og-Energidepartementet, 2020).

As a result of the opening of the two areas, potential developers are keen to know the feasibility of developing an offshore wind farm (OWF) in Norway. Feasibility studies are crucial for OW developers as large-scale projects carry significant investment cost, which will only increase over time as projects become larger. For an example, the planned 3.6GW Dogger Bank OW joint-venture project between Equinor and SSE partner is predicted to have a combined investment cost of up to £9 billion (Equinor, 2019). Consequently, it is essential for developers to assess the feasibility of a proposed OWF project in Norway in order reduce the risks of failure. This can be done by determining the viability of a project in terms of technology, regulations, resources, and return on investment.

1.2 Literature Review

A literature review over relevant feasibility studies within OW was undertaken. Keivanpour et al. (2017) outlines crucial elements in determining the feasibility of an OFW in a general sense. According to the study, the most crucial elements in the feasibility assessment are technical, geographical, economic, government policies, and technology.

Offshore wind technology factors are required to be considered when undertaking a feasibility study. As outlined by Zhixin et al. (2009), OWF key technologies can be divided into eight overall categories: foundations, selection of site, wind measurement, investigation, wind turbines, hoisting, electrical transmission technology, and operation of system. Each of these categories include several technologies which must be considered for the optimal planning of an OWF. Keivanpour et al. (2017) also adds that energy storage technologies need to be considered, such as pumped hydro in order to solve the issue of variability of wind power. Hydrogen production and storage could also be a viable option when considering future OWF. The suitable choice of OWF technologies should be carefully considered as it will have an impact on other feasibility elements such as economics.

In addition, the wind energy produced depends on the available wind resources in the area which can be simulated through weather models, mesoscale modelling methods, or LIDAR measurement tools. Considering that air density is an important parameter, the wind speed should be measured at the hub level of the wind turbine, normally at 90m above the sea level (Keivanpour et al., 2017). However, with wind turbines growing larger in size, the measurement needs to be done at higher elevations levels in order to accurately determine the wind resource. More ideally, wind speeds should be measured at different heights in order to provide more detailed overview of the wind speed profile, which will be helpful when deciding on the turbine design. Other important weather parameters mentioned in the study include ice assessment, wave height, lightning, hurricanes, earthquakes, tidal characteristics, currents, wake effects, and extreme wind gusts which affects the performance and design of the OWF. Elliott et al. (2012) adds that other technical elements to consider when designing an OWF are geotechnical, bathymetry, and geophysical conditions of the ocean bed. These are important elements to consider when deciding on foundation design, wind farm layout, cable layout, and installation activities. In brief, the technical parameters mentioned are important factors to consider in a feasibility study of an OWF as they provide information on the engineering design, the potential wind energy resource, and to describe the weather conditions during installation and maintenance activities.

On the geographical part of an OWF feasibility study, spatial planning is considered an important element as there are several competing forces to an ocean area (Keivanpour et al., 2017). In Hong and Möller (2012) study on implications of spatial constraint on the feasibility of China's 30GW offshore wind target by 2020, they listed oil & gas platforms, submarine cables and pipelines, shipping lanes, military training zones, natural conservation areas, fishing, visibility, and tourism as the main competing forces to suitable OWF areas. According to the study that aims to identify the most suitable locations for floating offshore wind turbines within the European Atlantic Area, Diaz and Soares (2020) argues that the operational needs of a floating wind farm need to be considered as well in the maritime spatial planning of the area considered for OWF. One of the current advantages of OW compared to onshore wind is the fact that there less public scrutiny and spatial competition. However, looking ahead, maritime spatial planning is likely to be an important factor as future OWF become larger in size and thus require more installation and maintenance ships. In a feasibility study for OWF, careful consideration needs to be done to the spatial planning in order to avoid or mitigate any issues with competing interests.

An economic feasibility study of an OWF is necessary to execute in order to determine whether the benefits of the project outweigh the costs. This is an especially important step when attempting to determine the attractiveness of investing in an OWF. This is also useful to governments as it provides them with information on how to develop support policies. It may also be helpful to developers and other industry actors to identify areas of improvements within the cost structure. There are five indicator which are common in determining the economic feasibility of an OWF: Levelized Cost of Energy (LCOE), Net Present Value (NPV), Internal Rate of Return (IRR), Discounted Pay-Back Period, and Cost of Power ratio (Castro-Santos et al., 2016). LCOE, commonly known as the break-even cost to generate energy, is a widely used indicator for calculating the cost of energy for a power plant over its lifetime and is quite useful when comparing different energy technologies in cost per kWh/MWh. When determining the LCOE it is important to include capital costs, operating costs, discount rate, annual energy production, lifetime, and financial structure (Levitt et al., 2011). There have been several economic feasibility studies undertaken for various projects in different countries. Satir et al. (2018) calculated the economic feasibility of an OWF in the Turkish seas by using the LCOE and NPV method. In the authors calculation of LCOE, the various cost inputs and other parameters were gathered through various studies, and to estimate the annual energy production the software program WindPRO was used. Mattar and Guzmán-Ibarra (2017) similarly used LCOE, NPV but also included Pay-Back period method to assess the economic feasibility of three different OWF sizes along the coast of Chile. Sensitivity analysis was also performed by changing various parameters in the calculations. It has been evident from these past studies that LCOE and NPV are useful tools when considering the economic feasibility of potential OWFs. Although far from perfect estimations, they can provide useful insights for government agencies when recommending policy support schemes. Additionally, these tools can aid developers and investors in the decision-making process regarding potential projects. Finally, it is possible that economic feasibility studies can highlight areas for improvements in the cost structure, helping stir innovation within the industry.

Government policies and regulatory framework are also vital to assess in order to determine the viability of an OWF (Keivanpour et al., 2017). Favorable government policies and financial incentives can improve the financial viability of a renewable energy project and is thus linked to the economic feasibility of an OWF. In general, examples of such supportive policies can be R&D financing, capital cost support, tax credits, feed-in-tariffs, green certificates, or other marked based incentives. Such policies can help reduce investment costs and increase revenue of a project, which is a necessary step to realize large scale OWF. Winje et al. (2020) compared policy tools from a socio-economic perspective needed to realize a large-scale floating OWF market in Norway. From a business economics perspective, large-scale floating OWFs fail to become realized in Norway due to the lack of profitability. However, from a socio-economic perspective the authors highlight positive externalities to the Norwegian supply chain from developing a home market for floating OWF. Therefore, there exists a gap between the sum of socio-economic benefits and the business economic benefit. To correct for this market failure, the government is compelled to step in by providing policy tools in terms of economic incentives or direct regulations. The authors compared policy tools widely used today in other European countries and concluded that the Contracts of Difference tool was the most cost-effective solution to realize large-scale floating OWF in Norway. The study highlights the importance of understanding any countries supportive policy tools in order to assess the feasibility of an OWF.

There is a lack of techno-economic feasibility studies for developing a specific offshore wind farm in Norway. Previous studies on the techno-economic feasibility of OWF specifically for Norway are mainly derived from the Norwegian Water Resources and Energy Directorate's (NVE) 2012 report *Offshore Wind Power in Norway – Strategic Environmental Assessment.* Berg et al. (2012) undertook a techno-economic feasibility along with impact assessments on business, public interest, and environment in order to choose the most suitable zones for potential OWF. The assessment of the economic feasibility includes all the factors that affect the cost and income structure associated with developing a 500MW OWF project over its lifetime in the different areas. The factors include development and decommissioning costs, total energy production based on meteorological conditions, water depth, and distance to nearest grid connection. To assess technical feasibility, three main criteria were chosen; geophysical conditions, technology maturity, and maturity of the supply chain to deliver supplies and services. In addition, the report includes an assessment of the flexibility to change a wind farm layout with minimum impact for turbine technology and/or energy production.

Finally, an assessment is made with regards to optimal grid connection, regional capacity in the net, and the need for grid investments. The report summarizes the authors main findings based on these assessments and concludes with 15 zones recommended to the Ministry of Oil and Energy (OED). Two of these recommended zones, Sørlige Nordsjø II and Utsira Nord, were announced open by the OED for license applications starting from January 1st, 2021. These two zones were assessed to have the best overall technic and economic conditions with minimal negative environmental impact for OWF development. Berg et al. (2012) comprehensive findings form much of the basis of this thesis and is thus a valuable tool.

With a lack of recent academic literature investigating the techno-economic feasibility for a specific OWF case in Norway, the author of this thesis intends to fill this gap by undertaking a techno-economic feasibility for a specific project in Norway.

1.3 Thesis research questions

As a result of the opening of the two areas, potential developers are keen to know the feasibility of developing an OWF in Norway. This thesis has chosen a hypothetical case from a possible applicant for a 550MW OWF site at Sørlige Nordsjø II. The master thesis is a feasibility study by performing a techno-regulatory-economic analysis of the selected project. As such, this thesis includes investigating the technical requirements, regulatory requirements, and economic feasibility of developing a 550MW OWF in the area Sørlige Nordsjø II. More specifically, the thesis is divided into the following sub questions:

1. *What are the legal/regulatory requirements for the 550 MW OWF in Norway?*
2. *What are the technical requirements for the 550 MW OWF in Norway?*
3. *Is the OWF project economically feasible in terms of transmitting and selling the electricity produced to the Norwegian power market?*
4. *Is the OWF project economically feasible in terms of transmitting and selling the electricity produced to the German power market?*
5. *Is the OWF project economically feasible in terms of transmitting and selling the electricity produced to the U.K power market?*

1.4 Methods

1.4.1 Regulatory

The primary source of information for the regulatory method will be through Lovdata.no to provide the thesis with the legal basis. As this is an ongoing discussion, regular interviews with senior engineer Ann Myhrer Østenby and engineer Jon Krogvold at NVE will be undertaken throughout the fall semester to understand the regulatory field with regards to the licensing process for offshore wind. Other inputs from various industry participants have will also be gathered from various industry participants.

1.4.2 Site Characteristics

Analysing the site characteristics will prove to be a challenge as the site has not been properly explored. That said, the author intends to use the online knowledge base Mareano. Mareano maps the ocean depths, seabed conditions, biological diversity, habitat types, and pollution in the Norwegian ocean area. It has been developed in collaboration between Havforskningsinstituttet, NGU, and Kartverket. The information gathered here will also be supported by the previous research for the area in NVE's 2012 report *Offshore Wind Power in Norway – Strategic Environmental Assessment.*

In addition, Svein Finnestad and Harald Brekke at the Norwegian Petroleum Directorate have expressed willingness to aid the author with information about the seabed. The Norwegian Petroleum Directorate possess a large amount of publicly available drilling data in near proximity which can be helpful in defining the seabed.

1.4.3 Calculating Annual Energy Production: WindPRO

WindPRO is the leading software program in designing and planning wind projects. It covers several tasks including wind data analysis, annual energy production along with its associated losses, technical analysis, economic analysis, and environmental analysis. The software is widely recognized in the industry and is even accepted by banks when making loan decisions for a project.

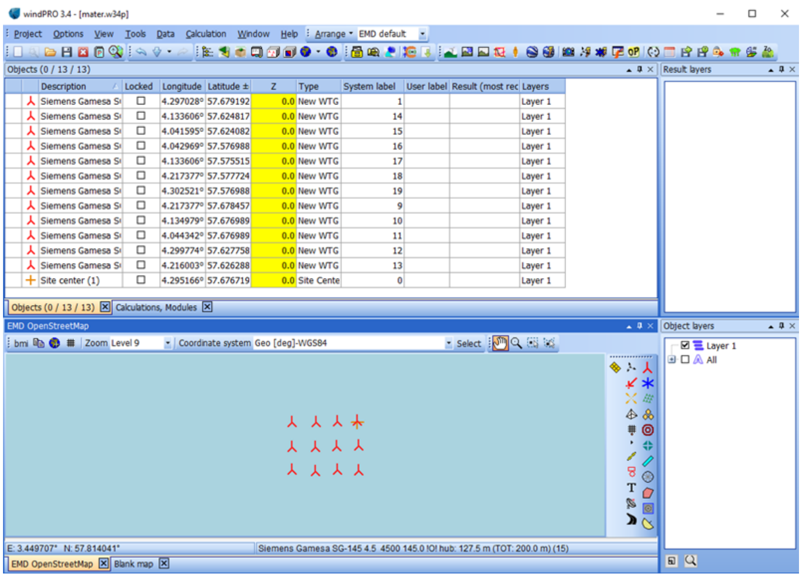


Figure 1 Screenshot of Windpro 3.4 Software tool. Authors own screenshot

For this master thesis, WindPRO version 3.4 was used by the author. Due to the short-term access period, WindPRO was limited to estimating the annual energy production and the optimal layout of the farm. The annual energy production is calculated in the software based on several parameters including input wind data, choice of turbine, climatic data, wake loss parameter, and other losses such as array cable losses. The 35-megabyte input wind data was provided by Stig Arild Fagerli at Stormgeo. The Stormgeo data is a ERA5 hourly time-series simulated up to 100m heights for the project region between the years 1999-2019.

Based on the resulting Annual Energy production, an economic analysis is conducted using the economic methods reviewed below.

1.4.4 Economic Methods

The economic methods used for this thesis will be based on business economics and will therefore not assess the socio-economic factors. Excel will be used for calculating the below mentioned methods.

1.4.4.1 Payback method

The payback method is a simple way to calculate the time required to earn back the amount invested in a project from its associated cash flow. This simple method can assess the risk of alternative projects as an investment with a shorter payback period is preferred for the investor. However, the simplicity of this method ignores the time value of money which is a drawback (Bøhren & Gjærum, 2016). The payback period in years for an investment is calculated as follows:

$$Payback\ period = \frac{Initial\ investment\ cost}{Annual\ cash\ flow}$$

1.4.4.2 Levelized Cost of Electricity

Levelized cost of electricity (LCOE) is a convenient and often used tool to measure the overall competitiveness of different energy-generating technology, usually represented in cost per kWh or MWh. It is defined as the aggregated discounted lifetime cost of generating electricity per unit of output (OEE, 2019). This is an especially supportive metric for policy makers, governments, and investors when making long-term decisions about which types of renewable energy sources to promote on which ones to deter. That said, the LCOE method is an abstraction of reality and only captures the associated lifetime costs with an energy project but ignores the revenue side. According to Kost et al. (2018) LCOE can be calculated on the basis of net present value (NPV). The authors point out that LCOE on the basis of NPV is usually applied for new generating plants, and can be calculated as follows (Kost et al., 2018):

$$LCOE = \frac{NPV\ of\ total\ costs\ over\ lifetime}{NPV\ of\ electricity\ produced\ over\ lifetime} = \frac{CAPEX_0 + \sum_{t=1}^{n} \frac{OPEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{AEP}{(1+r)^t}}$$

Where;

$CAPEX_0$ = upfront capital expenditure in year 0
n = operational lifetime of OWF project in years
t = individual year of operation
$OPEX_t$ = annual operating cost in year t
AEP = net annual energy production
r = discount factor

1.4.4.3 Net present value

The net present value (NPV) method helps to decide if a proposed project is an attractive investment. It is defined as the sum of all discounted net cash flows over the project lifetime minus the original investment. NPV is calculated as follows (Bøhren & Gjærum, 2016):

$$NPV = -A_0 + \sum_{t=1}^{n} \frac{a_i}{(1+\bar{r})^t}$$

Where;

A_0 = Investment CAPEX cost in year 0
a_i = net cash flow in year t
$\bar{r}$ = discount rate
n = lifetime of project

The following rules apply for the resulting NPV:

- If NPV>0, the project is profitable and should be accepted.
- If NPV<0, the project is unprofitable and should be rejected.

1.4.4.4 Internal Rate of Return

The internal rate of return (IRR) is closely tied with the NPV method. It is defined as the rate of return that makes the NPV equal to zero. To find the IRR, NPV is set equal to zero which the formula below illustrates, and from there solve for r to find IRR (Bøhren & Gjærum, 2016):

$$0 = -A_0 + \sum_{t=1}^{n} \frac{a_i}{(1+r)^t}$$

This method is widely used by investors to compare the attractiveness of different projects and to determine whether the project IRR covers the investors required rate of return. Therefore, the following rules apply from an investors point of view for the resulting IRR (Bøhren & Gjærum, 2016):

- If $r > \hat{r}$, accept project

- If $r = \hat{r}$, indifferent to project
- If $r < \hat{r}$, reject project

$\hat{r}$ is the investors required rate of return for the project.

1.5 Structure of thesis

The thesis is structured into 8 chapters.

Chapter 1 provides the reader with the introduction, background, literature review, research question, and methods used.

Chapter 2 provides the reader with the theoretical background, technology, and economic cost drivers for OW. If the reader is familiar and updated with this comprehensive chapter, then it is <u>strongly recommended</u> that he/she skips this chapter. The reason for including a comprehensive theoretical background is to provide a potential unknowing reader with the necessary theoretical background, updated technology status, and cost drivers for OW. Many of the technical choices for the proposed offshore wind farm are based on the information provided in chapter 2. Thus, if the reader is confused about why certain technologies or site conditions are chosen for this thesis, it is recommended he/she reads back on chapter 2.

In Chapter 3, the legal and regulatory requirements for developing OW in Norway will be presented.

Chapter 4 will introduce the 550MW case study. Here, the technical requirements along with the economic assessment and results will be analysed.

Chapter 5 discusses the results from chapter 3 and 4.

Finally, chapter 6 provides a conclusion along with recommendations.

Chapter 7 lists the references while chapter 8 provides an appendix.

2. Offshore wind: theoretical background, technology, and economics

2.1 Wind resource and characteristics

2.1.1 Wind physics: Kinetic energy

Wind turbines make it possible to harvest the kinetic energy of the wind and transforms it into usable electricity. When looking at the physics of wind, we need to start off by looking at the general physics of kinetic energy of an object, which is a function of mass (m) and velocity (v) (Manwell et al., 2010):

$$Kinetic\ energy = \frac{1}{2}mv^2 \tag{1}$$

However, wind contains several small molecular particles such as nitrogen, oxygen, carbon dioxide, each with kinetic energy. These particles have low mass so instead of looking at the kinetic energy of each particle, we look at mass flow of air through a specific area. That mass flow is going to be equal to the density of air (ρ), multiplied by the velocity of the air (v), multiplied by the swept area (A) (Manwell et al., 2010):

$$\frac{dm}{dt} = \rho A v \tag{2}$$

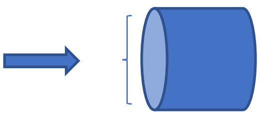


Figure 2 Mass flow of air through disc of area

Substituting mass flow equation (2) in kinetic energy equation (1), we find equation to calculate the power available in the wind (P) (Manwell et al., 2010):

$$P_{wind} = \frac{1}{2}\frac{dm}{dt}v^2 = \frac{1}{2}\rho A v^3 \tag{3}$$

Where;

P = power (watt)
ρ = air density (kg/m^3)
$A = \pi r^2$, where r is the rotor radius (m)
v = wind speed (m/s)

From this equation (3), the key takeaway is that the velocity of the air is particularly important to the wind power. With all things being equal, the power of the wind is cubically related to the wind speed. For an example, a doubling in wind speed will result an eightfold increase in power. Also, the power output is positively correlated with the turbine swept area by way of increasing the diameter of turbine. Finally, the power output from the wind turbine is linearly correlated with the air density. The air density depends on the height above sea, air temperature, humidity, and barometric pressure (Trømborg, 2019). When the temperature falls the air density increases, which in turn increases the power available in the wind.

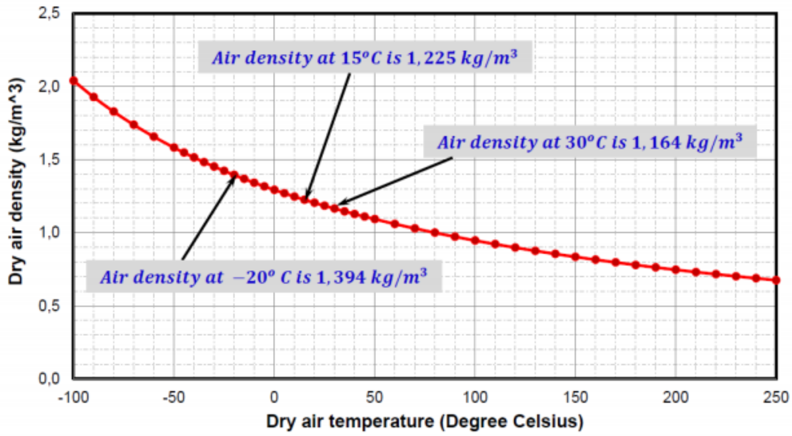


Figure 3 Air density versus air temperature at standard atmospheric pressure. Trømborg, E. (2019). Vindkraft I : Forn200. Ås, Universitet for miljø og biovitenskap.

2.1.2 Betz Limit

It is a known fact that every generation system is less than 100% efficient. In other words, it is not possible to convert one form of energy into a more useful form of energy without losses. This is also the case for wind turbines when capturing the energy from wind power. In order to capture the loss, equation (3) needs to incorporate a power coefficient (C_p) which defines the efficiency of a certain wind turbine and is dependent on the wind speed (Manwell et al., 2010):

$$P_{Turbine} = \frac{1}{2}\rho A v^3 C_p \quad (4)$$

According to Albert Betz, there is a maximum amount of energy that can be extracted by the wind turbine. This limit, also known as Betz limit, and is defined as the ratio power extracted by the wind turbines to the total power in the wind. This theoretical limit is set at maximum efficiency value of 59.3% that any wind turbine can convert into mechanical energy (Manwell et al., 2010). In practice, the maximum efficiency of commercial wind turbines lies between 40 and 50% at ideal wind speeds (Masters, 2004). This is among other things due to inefficiency in the power system and the gearbox.

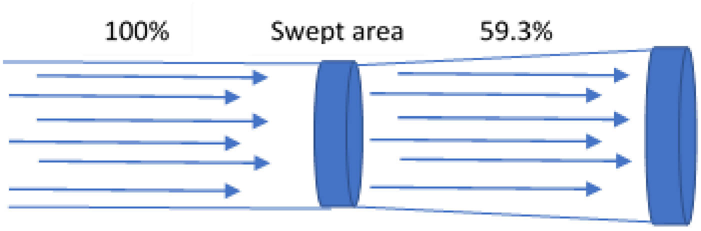


Figure 4 Betz limit of 59.3%. Authors own

The turbine spin causes the air molecules to spin after it passes through as illustrated in figure 5. This is known as wake rotation and turns into wasted energy (Manwell et al., 2010).

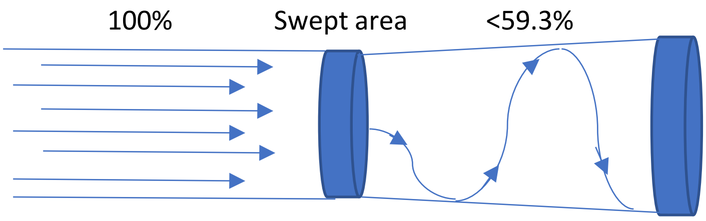


Figure 5 Wake rotation loss. Authors own

As a result, there is a difference between the theoretical max power in the wind, the theoretical limit based on Betz limit, and practical power curve of a turbine.

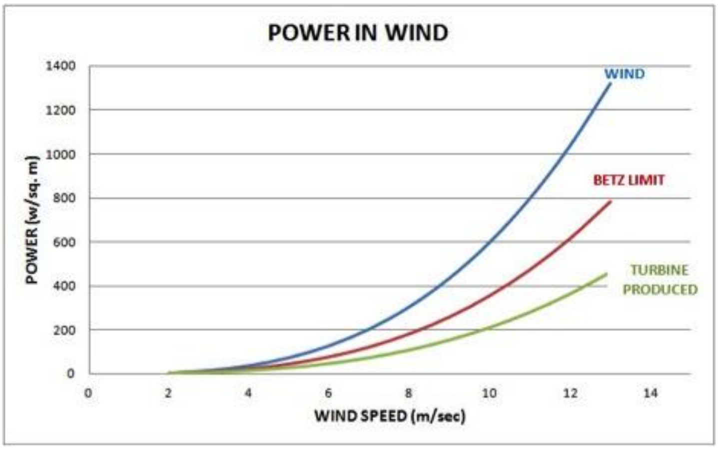


Figure 6 Wind power vs Betz Limit vs Power produced by turbine. Windynation. (2010). How Much Power will a Wind Turbine Produce. Retrieved from Windynation: clean power to the people: https://www.windynation.com/jzv/inf/how-much-power-will-wind-turbine-produce

2.1.3 Aerodynamic design of wind turbine blades

What all wind turbines have in common is that they extract kinetic energy from the wind and convert it into a mechanical torque through rotor aerodynamics. It is necessary to understand how a wind turbine rotor works and how the design transforms the linear motion of the wind into a rotation of the turbine.

A rotor blade is defined by a spanwise distribution of aerodynamic profiles called airfoils, which vary in thickness, shape, and performance. The blade section will be a few meters long and define the surface of the blade (Mamadaminov, 2015).

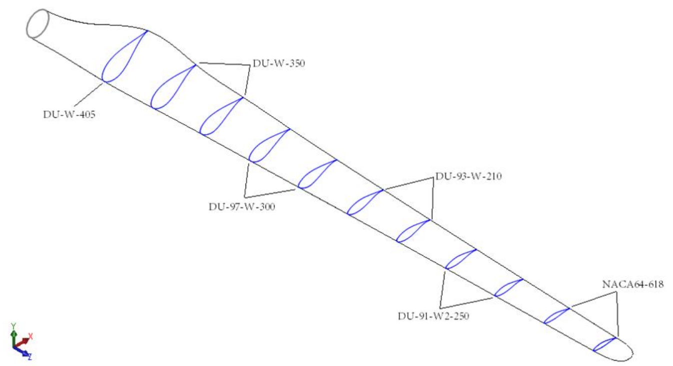


Figure 7 A 50-meter-long turbine blade with different airfoils. Monteiro, L. F. (2015, December 31). Grabcad Community. Retrieved from https://grabcad.com/library/wind-turbine-model-flow-study-1

The aerodynamics over the blade section are defined by the shape of the blade and by the development of the viscous flow close to the surface, creating a layer of a few millimetres. In this boundary layer, over the coating of the surface, small perturbations appear. These perturbations are small vortices generated by the forces on the surface that are fractions of millimetres and which grow, defining the final aerodynamic performance of the wind energy conversion system. These sub-millimetre vortices coalesce into a vortex sheet of the size of a blade. In a wind farm, these sheets coalesce in a system of vortices that exchange the energy with the upper part of the atmospheric boundary layer (Mamadaminov, 2015)

An airfoil of a wind turbine is generated to create the aerodynamic force lift while minimizing the other force drag. Lift is the aerodynamic force that is perpendicular to the wind speed that the airfoil perceives. This force is only possible when creating the microscale vortices on the surfaces of the airfoil that will create the wake of the wind turbine. Drag is the aerodynamic force that is aligned with the perceived wind speed. In a wind turbine, the blade section will therefore experience two sources of wind. First, natural wind flowing through the turbine. Second, an apparent wind from the flight path of the blade due to its rotation. With these two wind directions, there will be to components of lift. The natural wind will generate a force perpendicular to wind direction, which is in the direction of rotation of the blade and propels it, creating torque (Mamadaminov, 2015).

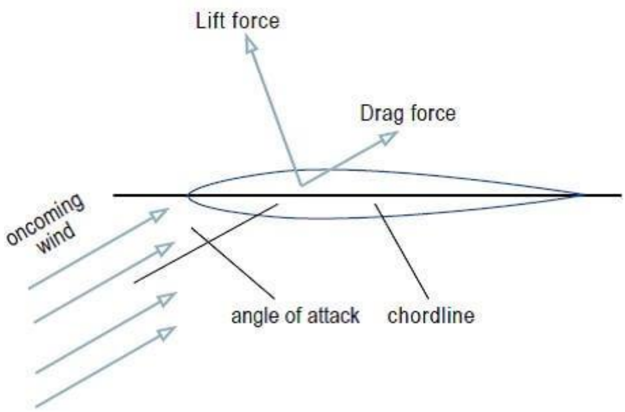


Figure 8 Illustration showing the aerodynamic lift and drag forces on an airfoil along with the wind flow direction. Spiegel, C. (2018, July 9). FuelCellStore. Retrieved from Energy Harnessed from the Wind: Part 2: https://www.fuelcellstore.com/blog-section/energy-harnessed-from-the-wind-part-two

The wind, due to the rotation of the blade, will create a force against the natural wind, and is responsible for decelerating the wind. At the air foil and rotor scale, the wind can be seen to decelerated, losing kinetic energy. It is this energy that is converted into the mechanical energy of torque and power, which is fed into the drive train through the blade. The blade of a wind turbine is designed to take as much energy as possible at minimum cost. Thus, the rotor blade of a wind turbine is a key part of the power produced through aerodynamic efficiency but needs to consider economic factors as well (Mamadaminov, 2015).

2.1.4 Power Curve of wind turbines

The power produced by a wind turbine depends on its power curve, which illustrates the power as a function of wind speed. This, however, holds only for a certain range of wind speeds. The wind speed at which the rotor begins to rotate is called the cut-in speed, typically this is about 3-4 m/s (Jalilinasrabady et al., 2015). Below this value, no power is produced. Conversely, if the wind is too strong, the resulting load on the rotor can damage the turbine. The cut-out speed is the utmost wind speed at which the power can be safely produced by the turbine, and usually lies at wind speeds of around 25 m/s (Adaramola, 2019). Finally, the turbine generator also imposes a limit on the power output. Thus, the power produced by the turbine is limited to constant value once it reaches a certain wind speed. This value is called the rated power and varies between the different turbines (Jalilinasrabady et al., 2015).

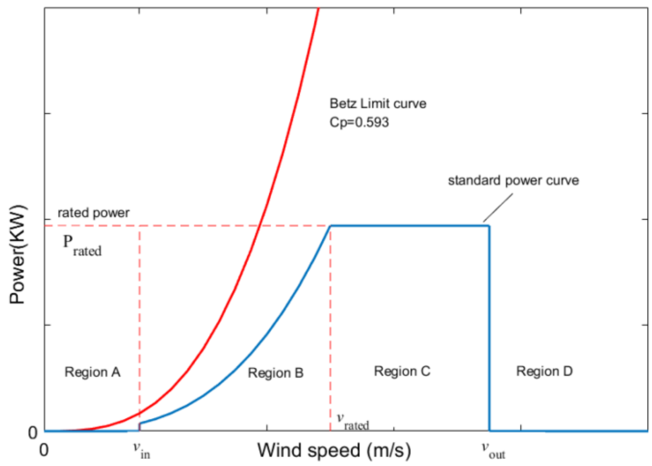


Figure 9 Standard power curve. In region A, no power is produced until cut-in speed at v_in. Power increases with wind speed in region B up to the point of v_rated, which becomes constant in region C. v_out is cut-out speed in which turbine stops producing due to technical concerns. Xiao, Z., Zhao, Q., Yang, X., & Zhu, A. (2020). A Power Performance Online Assessment Method of a Wind Turbine Based on the Probabilistic Area Metric. Applied Sciences, 10(9), 3268

Each wind turbine has its own power curve which is provided by the wind turbine manufacturer. For an example, an Enercon E-126 7,58MW wind turbine has a max power coefficient of 0,483 at 10 m/s, cut-in speed at 3 m/s, and cut-out wind speed at 28 m/s (Enercon, 2015). The power coefficient C_p increases up to 10 m/s, but then starts to decline between 10 m/s and 25 m/s due to increasing difficulty for the blades to capture the energy from the wind. The declining power coefficient eventually results in the power P being held constant between 16 m/s and 28 m/s, which is the point of cut-out. Wind speeds at these high levels are a rare occurrence during the year, which is something we will investigate in the next section.

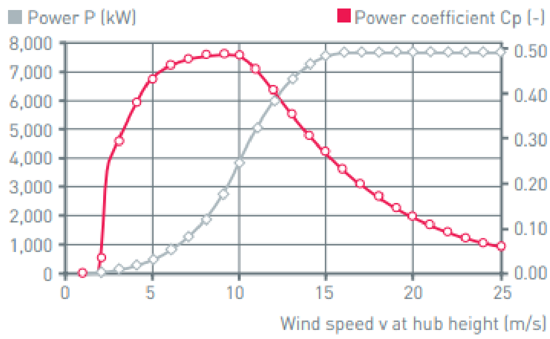


Figure 10 Enercon E-126 power curve with power coefficient curve. GmbH, E. (2015, June). wind-turbine.com: global marketplace. Retrieved from https://wind-turbine.com/download/101655/enercon_produkt_en_06_2015.pdf

2.1.5 Wind resource assessment at site

In addition to the power curve of a turbine, the power produced by a turbine depends on a site's wind resource.

2.1.5.1 Global and local wind

Wind is created when air flows from one area to another. The air flows from on area to another due to the sun heating the Earth at different locations, creating temperature gradients across the globe. Hot air tends to rise in the atmosphere, while cold air tens to fall towards the ground. This generates global recirculation of air between regions at different temperatures (Bussel, 2008)

In addition to these global motions, local effects arise due to the differences in terrain. This can be seen from typical wind velocity profiles as a function of the altitude. The wind velocity increases from zero at the ground to a certain value in the atmosphere. However, the exact shape of the profile depends on the local topography. Above sea, the increase will be much steeper. This means that at sea the wind speed is more unform with the altitude. By contrast, in urban or countryside areas, the wind is slowed down by the presence of buildings and trees. This means that the wind speed will reach a constant value at a much higher altitude than at sea. In short, offshore wind turbines generally benefit from much stronger and uniform winds (Bussel, 2008)

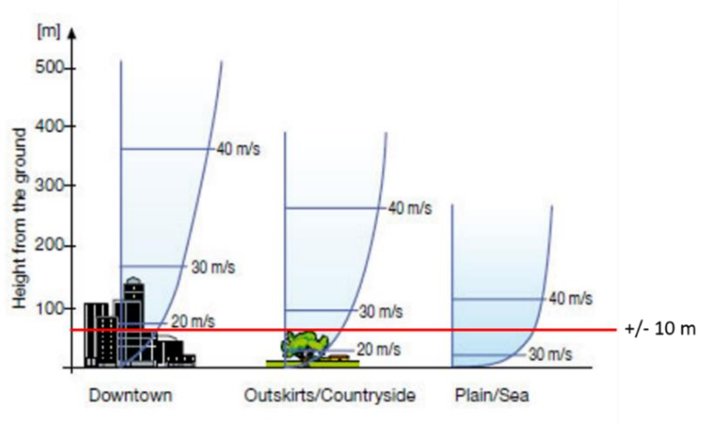


Figure 11 Vertical wind profile for different terrains. Nelen & Schuurmns (2020). "Wind Effects." Retrieved 2020, 7/12, from https://docs.3di.lizard.net/b_wind.html.

These global and local variations in wind are associated with different length and time scales. Global variations can occur over distances of hundreds or thousands of kilometres and time scale in order of months or seasons. By contract, local effects due to the type of terrain vary over shorter distances and small-time scales. The sea breeze is a daily event, whilst the turbulence created by urban obstacles changes every minute or seconds (Bussel, 2008).

2.1.5.2 Wind time-series data

Due to the variations in wind, it is necessary to measure and illustrate the time evolution of the wind speed at a specific location. This is especially important in the pre-development phase of a wind farm as the data provides a basis for choice of turbines, economic analysis, and even loan applications (Adaramola, 2019). The time evolution will encompass all the global and location variations as previously discussed, providing a time-series data of the wind speed.

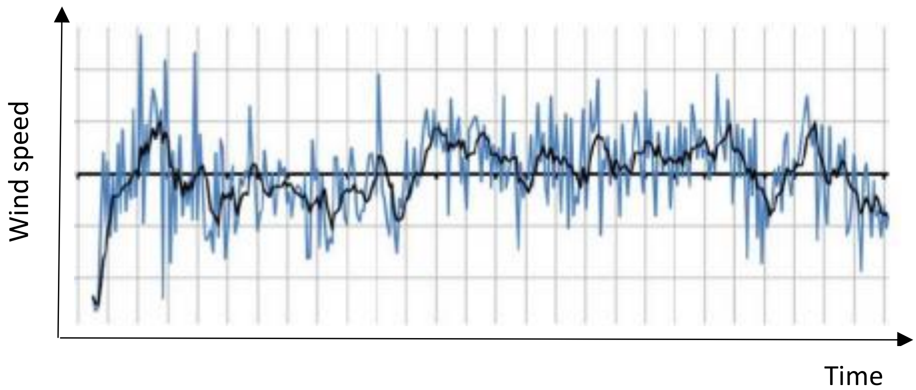


Figure 12 Example of time-series wind data. Trømborg, E. (2019). Vindkraft I : Forn200. Ås: Universitet for miljø og biovitenskap (Lecture 23.10.2019).

The duration of the time-series measurement should be at least one year to capture the seasonal variations and provide reliable data (Adaramola, 2019). However, according to business development manager Mathias Van Steenwinkel at offshore wind developer Parkwind (conversation on 14th October 2020), they prefer a time-series data in 10-minute intervals over 20 years for any pre-development stage. Furthermore, the measurement of the wind should take place at the hub height of the planned turbines.

2.1.5.3 Mean wind speed

For a simple estimation of the wind resource in area, it is possible to calculate the mean wind speed of measured parameters over a time period through the following calculation (Adaramola, 2019):

$$V_m = \frac{1}{N}\sum_{i=1}^{N} V_i \qquad (4)$$

Where;

V_m = mean wind speed (m/s)
V_i = wind velocity (m/s)
N = number of wind data

2.1.5.4 Probability density function

However, mean wind speed calculation can be misleading as it does not capture the wind speed distribution, which is important when determining the turbine class (Norwea, 2018). In order to rectify this, the wind measured can instead be assumed to be stationary over intervals of time, often in 10-minute intervals. For each interval we can then compute a mean velocity and count how many times a certain mean velocity occurs in the data and place this information in a histogram.

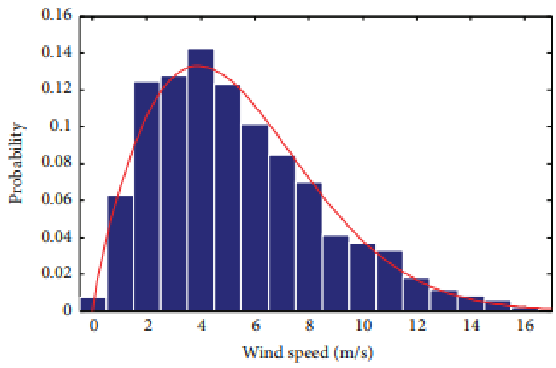


Figure 13 Histogram (in blue) and Weibull probability density function (red line) of wind speed data.l Ditkovich, Y., & Kuperman, A. (2014). Comparison of three methods for wind turbine capacity factor estimation. The Scientific World Journal, 2014.

The histogram will show how often each wind speed occurs but can be more precisely represented by a continuous probability density function (PDF). This will show the probability of occurrence of a given wind speed. There are two widely used PDF's for describing wind speed data; Weibull PDF and Rayleigh PDF.

The Weibull PDF is given by Bidaoui et al. (2019) as:

$$f(V) = \left(\frac{k}{c}\right)\left(\frac{V}{c}\right)^{k-1} exp\left[\left(\frac{V}{c}\right)^{k}\right] \tag{5}$$

Where;

$f(V)$= probability of observed wind speed V (m/s).
k = dimensionless Weibull shape parameter.
c = Weibull scale parameter (m/s).

For annual wind speeds of greater than 4,5 m/s, it is more common to use the Rayleigh PDF (Adaramola, 2019). Rayleigh PDF is a different case of Weibull distribution with and is defined by Bidaoui et al. (2019) as:

$$f(V) = \frac{\pi V}{2V_m^2} exp\left[-\frac{\pi}{4}\left(\frac{V}{V_m}\right)^2\right] \tag{6}$$

Where;

$f(V)$= probability of observed wind speed V (m/s).
V= wind seed
V_m= mean wind speed (m/s)

Table 1 Overview over other important wind measurement parameters. Adaramola, S. (2019). Site Wind Resources Evaluation : Forn300 Hydropower and Wind Energy. Ås, Universitetet for miljø- og biovitenskap.

Variable	Equation	Units	Comments
Standard deviation	$\sigma = \left[\frac{1}{N}\sum_{i=1}^{N}(V_i - V_m)^2\right]^{\frac{1}{2}}$		Measures the level of variability and/or turbulence in wind speed
Turbulence intensity	$T_i = 100 * \frac{\sigma}{V_m}$	%	Calculates intensity of turbulence
Average wind power density	$\frac{\bar{P}}{A} = \frac{1}{2}\rho\left[\frac{1}{N}\sum_{i=1}^{N}V_i^3\right]$	W/m^2	Calculates average available wind power per unit area
Wind speed carrying maximum energy	$V_{maxE=c*}\left(\frac{k+2}{k}\right)^{\frac{1}{k}}$	m/s	From Weibull distribution function, closely related to rated wind speed of a wind turbine.
Wind speed carrying maximum energy	$V_{maxE=2V_m\sqrt{\frac{2}{\pi}}}$	m/s	From Weibull distribution function, closely related to rated wind speed of a wind turbine.

2.1.5.5 Wind rose

The wind direction is commonly characterized in a wind rose. It gives a diagrammatical representation showing the speed, direction, and percentage of time the wind blows in a particular area. The diagram comprises of radial lines which represent wind directions in directions North, East, South, and West. In addition, the concentric lines indicate the wind occurrence in percent, while the colour coded bars on each radial line indicate the wind speed. A wind rose diagram is especially useful when choosing a site and orientation for the wind turbines (Trømborg, 2019).

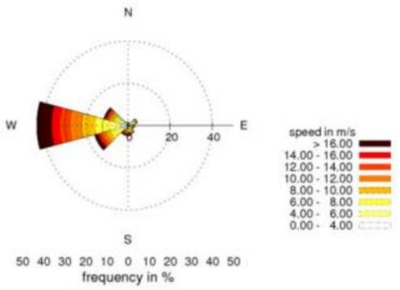


Figure 14 Example of a wind rose diagram. From this example we can see that the wind predominately comes from the west. Source : Trømborg, E. (2019). Vindkraft I : Forn200. Ås: Universitet for miljø og biovitenskap (Lecture 23.10.2019).

2.1.6 Estimated annual energy production

With the information from the Weibull or Rayleigh PDF equation (5) or (6) and the rated power curve of a wind turbine presented by the manufacturer, it is possible to estimate the energy generation. This can be mathematically expressed as follows (Adaramola, 2019):

$$P_{ave} = \sum_{i=1}^{N} P(V_i) * f(V_i) \tag{7}$$

where;

P_{ave} = average power
$P(V_i)$ = the wind turbine power from the power curve of wind speed V_i
$f(V_i)$ = probability distribution function

From (7), we can calculate the annual energy production of a turbine in kWh or MWh:

$$AEP = \varepsilon * 8760h * P_{ave} \tag{8}$$

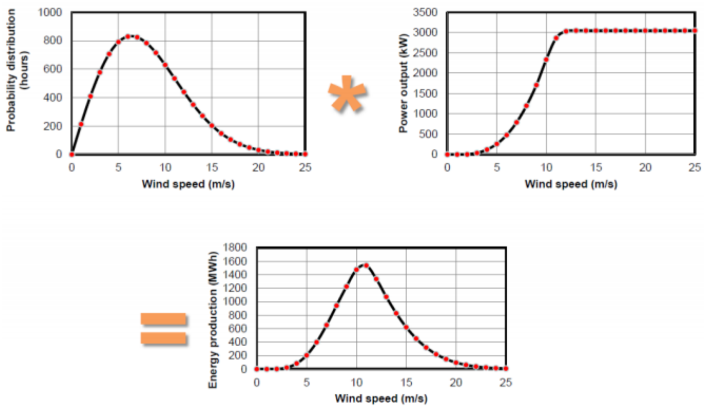


Figure 15 Calculating energy output through probability distribution and rated power curve of turbine. Source: Trømborg, E. (2019). Vindkraft I : Forn200. Ås: Universitet for miljø og biovitenskap (Lecture 23.10.2019)

2.1.7 Capacity factor

The capacity factor of a wind turbine the fraction of mean power output to the rated electrical power, or actual energy output divided by hypothetical maximum power capacity (Adaramola, 2019). In other words, the capacity factor indicates the percentage of time a system runs at full power over a reference period. If a wind turbine runs at full power during an entire year without interruption, its capacity factor would be 1. On the other hand, if the same wind turbine is switched off all year, its capacity factor would be 0. Mathematically, the capacity factor C_F can be defined as follows (Adaramola, 2019):

$$C_F = \frac{Power_{actual}}{Power_{rated}} = \frac{Power_{actual} * time}{Power_{rated} * time} = \frac{Annual\ Energy\ Production_{actual}}{Power_{rated} * 8760h}$$

Capacity factor is an important metric as it has a profound impact on the economics of energy production. If two similar turbines have different capacity factors, the turbine with the higher capacity factor will produce more energy and thus be more economical. It is also for this reason that the wind resource of a proposed wind farm must be thoroughly investigated before development. Windier sites result in wind farms with higher capacity factor and more profitable results. Commercial wind turbines typically have capacity factors from 20-50%, depending primarily on how good the wind resource is (Adaramola, 2019). Thus, offshore wind turbines tend to have better capacity factors than onshore wind turbines due to superior wind resources.

2.1.8 Wake effect

Like all energy systems, there will be some losses that need to be considered when optimizing an OWF. Wake losses are one example of such losses which needs to be identified and minimized. Wind farms contain several wind turbines, all extracting momentum and energy from the wind. The turbines that are extracting the energy from the wind at the front row will create turbulences and reduced wind speed after the wind passes the rotor, which was briefly illustrated earlier in figure 4. The result is that the turbines directly downstream of those front row turbines will potentially face more turbulent and deficit wind speeds, producing less energy. This is known as the wind turbine wake effect (Shakoor et al., 2016).

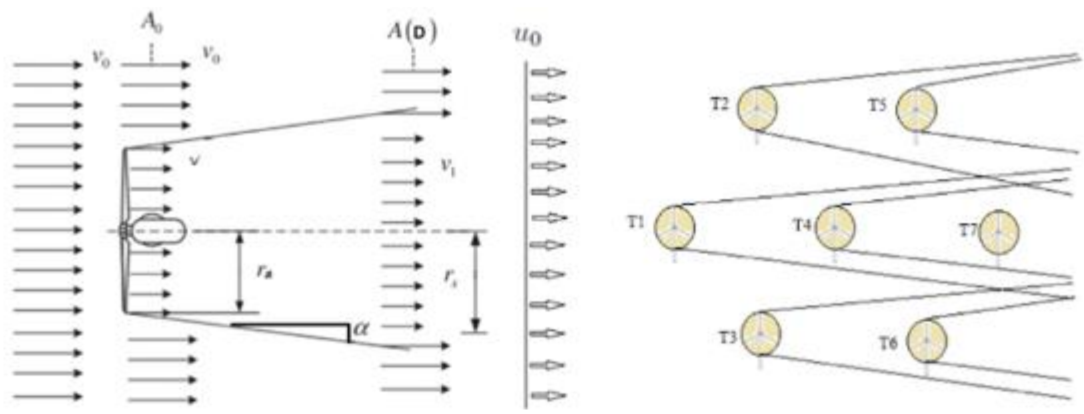


*Figure 16 Jensen's single wake model image to the left, and right multiple wake effect in wind farm to the right. The radius of the wake (r) expands linearly with respect to distance (D) and wind speed (v) is reduced from v0 to v1. Wake effect becomes more severe with multiple turbines on image to right: turbine T4, T5, T6 experience single wake effect, while T7 experiences multiple wake effect. Sources both images: Shakoor, R., et al. (2016). "Wake effect modelling: A review of wind farm layout optimization using Jensen 's model." Renewable and Sustainable Energy Reviews **58**: 1048-1059.*

According to Barthelmie et al. (2009), the wind turbine wake effect can result in losses between 10 to 20% of total power output in large OWF. Ideally an OWF would be concentrated into a small area to limit the length of expensive cabling, but because of possible wake losses the OWF needs to be carefully designed. A rule of thumb is to keep a distance of 5-6 turbine rotor diameters between the front row and the row directly behind it, and a distance of 3-4 rotor diameters across from each other (Norwea, 2018). For an example, turbines with a rotor diameter of 200m should be placed at least 1 km from front to back and 600m across from each other in an OWF layout.

Figure 17 Real-life photography of wake effect at Vattenfall's Horns Rev 1 wind farm. Source: Fialka, J. (2017, December 11). 'Wake' mystery is mostly fixed, helping turbines best coal. Retrieved from E&E News: https://www.eenews.net/stories/1060068565

2.2 Offshore Wind Power technology

This section will give the reader an overview over the main technology components of an OWF. Figure 18 illustrates the main components in an OWF, and much of the technology development has been achieved mainly by borrowing the technology and knowledge of onshore wind energy.

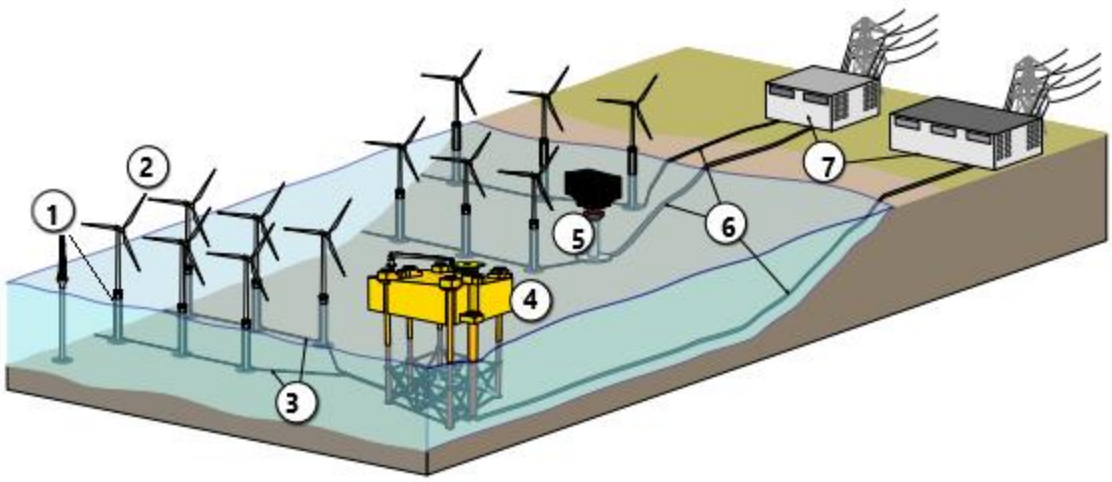


Figure 18 Main technology components of an OWF. (1) Foundations:; (2) Wind turbines; (3) Array cables; (4) Converter station; (5) Transformer station; (6) Export cables; (7) Onshore substations. Source : Rodrigues, S., Restrepo, C., Katsouris, G., Teixeira Pinto, R., Soleimanzadeh, M., Bosman, P., & Bauer, P. (2016). A multi-objective optimization framework for offshore wind farm layouts and electric infrastructures. Energies, 9(3), 216

2.2.1 Foundations

Foundations act as support structures for the OW turbines and keep them safely above the water and waves. The dynamic and powerful natural forces in the sea make the foundations particularly important. There exists a variety of different foundations technologies, each with different design, sizes, and materials. When choosing the correct foundation, several engineering factors need to be considered, including soil conditions, loads, transportation, water depth and installation (Zhang et al., 2016). It is also important to choose the most cost-effective solution as foundations make up approximately 15% of the total CAPEX for an OWF project (Wu et al., 2019). Generally, foundations for OW turbines can be divided into two categories: fixed and floating.

In the category fixed, the foundation is directly built into the seabed to provide a firm base on which the turbine sits on. The fixed offshore foundations share similar characteristics as onshore foundations, with the differences being that they are bigger due to the water depth and are designed to withstand the harsh marine environment. Fixed foundations can typically be found in shallow waters with water depths between 0-30m and transitional water depths between 30-70m. According to Business Development Manager Mathias Van Steenwinkel at OW developer Parkwind, 60-70m water depths draws the line for what is economically feasible for fixed foundations due to the use of steel (conversation on 14th October 2020). The shallow water foundation types include gravity-based, bucket, and monopiles. For the transitional water depths, developers have the option of tripod, tripile, twisted jacket, and jacket foundations. The majority of all the fixed foundations are made up of steel (Sánchez et al., 2019).

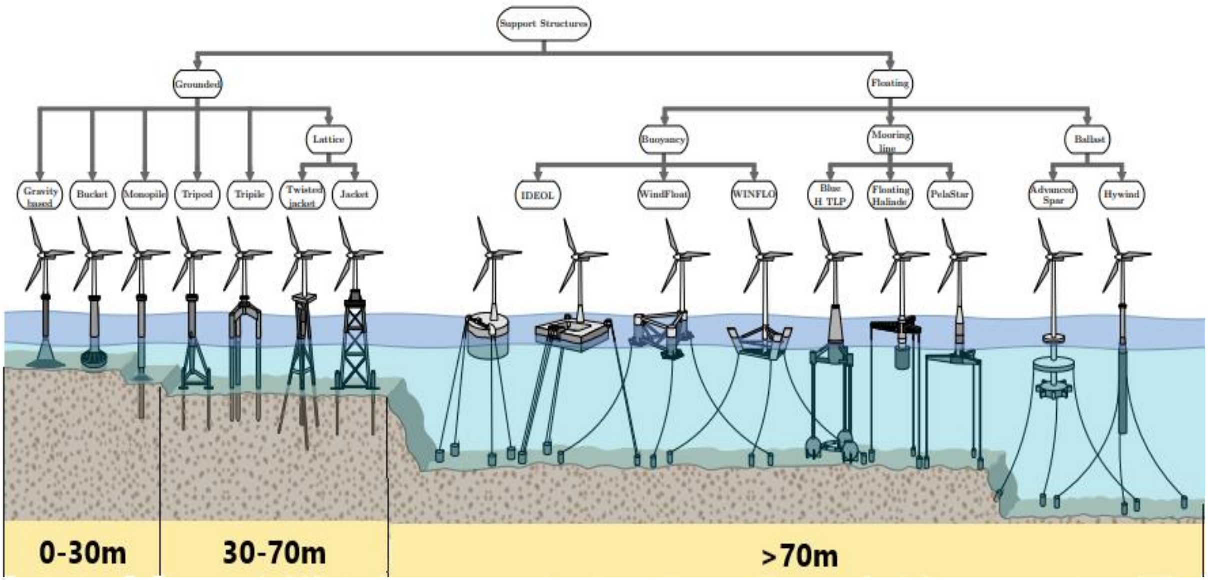


Figure 19 Different examples of foundation structures for OW turbines categorized into different water depths 0-30m, 30-70m, and larger than 70m. Source: Rodrigues, S., Restrepo, C., Katsouris, G., Teixeira Pinto, R., Soleimanzadeh, M., Bosman, P., & Bauer, P. (2016). A multi-objective optimization framework for offshore wind farm layouts and electric infrastructures. Energies, 9(3), 216

For deeper waters with depths above 70m, an alternative method is to use floating foundations. According to Zountouridou et al. (2015), floating foundations technologies could be feasible in water depths up to 700m. This technology offers many advantages in deep waters over fixed foundations in terms of installation, construction, decommission, and especially cost (Oh et al., 2018). The use of floating foundations decreases the cos of deep-sea installations, but also increases the technological challenges. Rather than a fixed solution, a floating foundation is connected from sea surfaces to the seabed with anchor lines. The main challenge for floating wind technology is how their floating foundations are designed to handle rough wind and wave conditions in deep waters while providing enough buoyancy to support the heavy turbines. The turbine must be stabilized and adjusted at sea in order to produce the maximum possible power. Here too, different designs exist, mostly depending on the water depth at which the turbine is located in. With these different designs, the entire wind turbine can move in heaves and in pitch. There are approximately 22 floating wind concepts under development that could possibly lead the way in the future, however the current dominant technologies include tension leg platforms, semi-submersible, and spar buoys. These technologies are dominant because they are attached to pre-commercial and commercial projects expected to be developed soon (Thema Consulting, 2020).

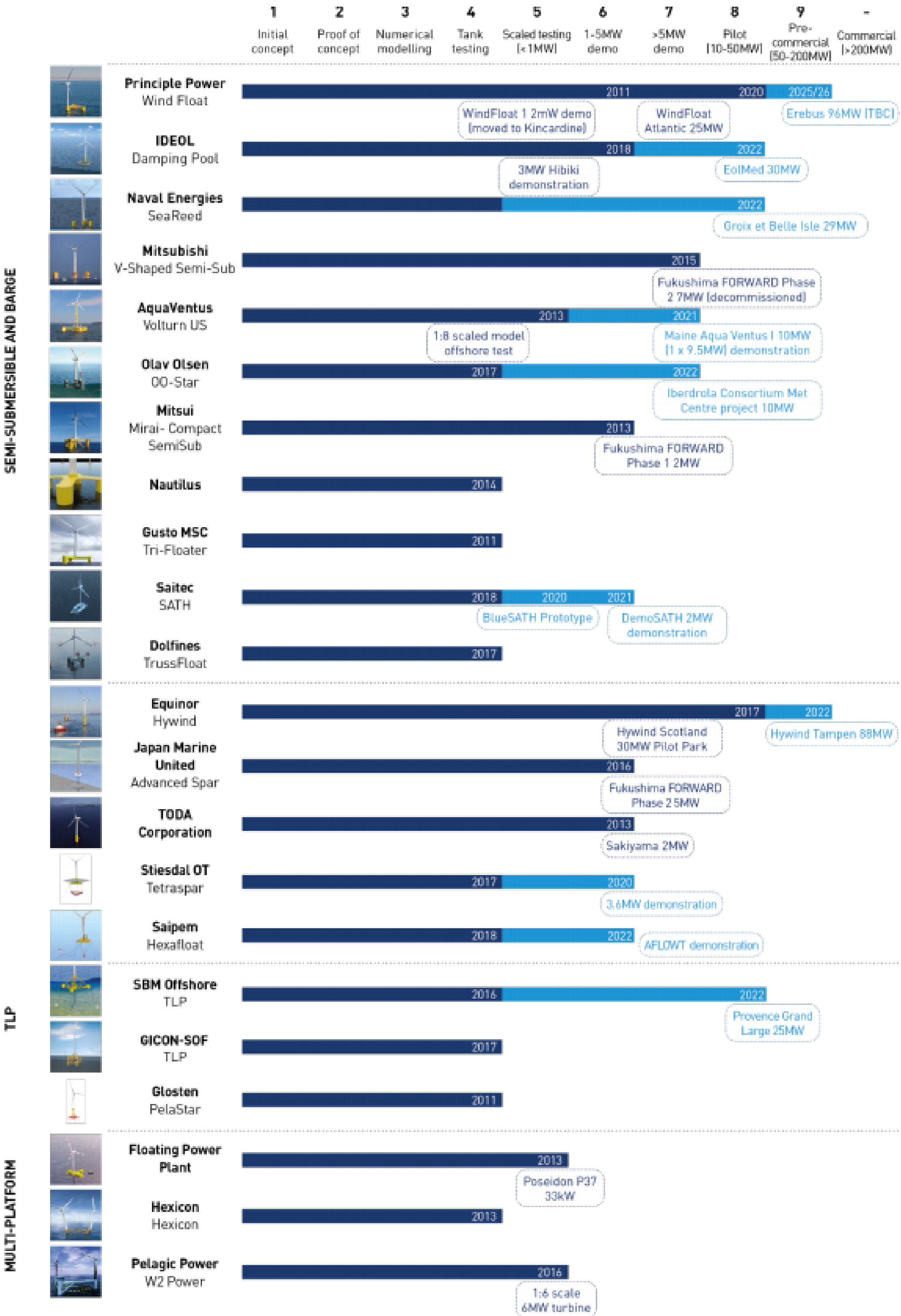


Figure 20 Overview over current floating wind concepts and their development phase. Source: Carbon Trust (2020). "Phase II summary report: Floating Wind Joint Industry Project." Retrieved 7/11/2020, 2020, from https://prod-drupal-files.storage.googleapis.com/documents/resource/public/FWJIP_Phase_2_Summary_Report_0.pdf.

Most of the current OW deployment has been on fixed-bottom foundations due to the "lowest hanging fruit" principle, i.e. the majority of the developed projects developed have been completed in water depths of 30m and below due to comparatively lower cost structure. Globally there is 27,000 MW installed globally using fixed foundations, while for the various floating type there has been only 82MW installed. In Europe, the monopile fixed foundation make up approximately 82% of the current total installed capacity (Wind Europe, 2019a). That said, the floating share will likely grab a larger share over time as the industry moves towards deep-water projects.

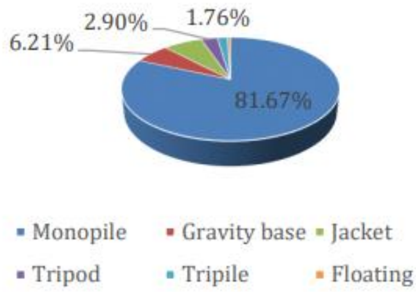


Figure 21 Share of installed OW foundations in Europe. Authors own. Data obtained from Windeurope Offshore Statistics https://windeurope.org/data-and-analysis/statistics/

In addition to cost and water depth consideration, the developer needs to consider the geological seabed when choosing the ideal foundation for the project. Table 2 summarizes the preferred geological conditions for each foundation type. According to ICF (2020), clay and sand are the preferred geological conditions for most of the foundation types.

*Table 2 Overview over preferred geological conditions along with examples of developed wind farms for each foundation type. Source 1s : h, K.-Y., et al. (2018). "A review of foundations of offshore wind energy convertors: Current status and future perspectives." Renewable and Sustainable Energy Reviews **88**: 16-36. Source 2: ICF. 2020. Comparison of Environmental Effects from Different Offshore Wind Turbine Foundations. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Headquarters, Sterling, VA. OCS Study BOEM 2020-041. 42 pp*

Foundation type	Maximum Water depths	Preferred geological conditions	Developed wind farms
Gravity-based	30m	Clay, bedrock, sand, cobbles, boulder, coarse gravel	48MW “Kårehamn” in Sweden, water depths between 6-20m
Bucket	30m	Clay and fine to medium sand	312 MW “Borkum Riffgrund 1” off Germany at 25m water depth.
Monopile	30-50m	Clay and sand	160 MW “Horns Rev 1” in North Sea, Denmark. Water depths between 6-14m
Tripod	50m	Stiff clay, medium to dense sand, softer silts, soft sediments overlying bedrock	400MW “Bard Offshore 1” off Germany with water depths between 39-41m.
Tripile	40m	Sand and clay	60MW “Alpha Ventus” off Germany in water depths between 28-30m
Jacket	60-70m	Same as Tripod. Non-rocky	10MW “Beatrice” demonstration project off UK in water depths of 45m
Tension leg platform	>70m	Medium to stiff clay, sand, gravel	2.3 MW pilot project off the coast in Germany
Semi-submersible	>70m	Same as tension leg platform	25 MW “Windfloat Atlantic” off Portuguese coast in water depths of 100m
Spar Buoy	>80m	Same as tension leg platform	Equinor 30 MW “Hywind Scotland” off coast of Scotland in water depths between 95-129m

2.2.2 Offshore Wind Turbines

Mounted on top of the foundations, the turbines can also come in a variety of designs. Like onshore turbines, the main OW turbines can be either a vertical axis wind turbine (VAWT) or horizontal axis wind turbines (HAWT) in terms of the orientation of rotating axis. The HAWT captures the wind energy with a rotor and their axis is parallel to the direction of the wind. On the other hand, the VAWT captures wind energy with a rotor with rotating axes perpendicular to the direction of the wind. The advantages of using the VAWT over the HAWT design is a reduction in required parts and hence costs. In addition, the VAWT can catch the wind in any direction without the need for reorientation. However, HAWT is mostly deployed offshore due to their superior aerodynamic efficiency over the VAWT. This is because the HAWT blades all capture the wind when the energy blows through, while only a fraction of the VAWT blades generate energy. Similar to onshore, the vast majority of OW turbines are 3 bladed HAWT where their axis of rotation is parallel to the sea (Kumara et al., 2017).

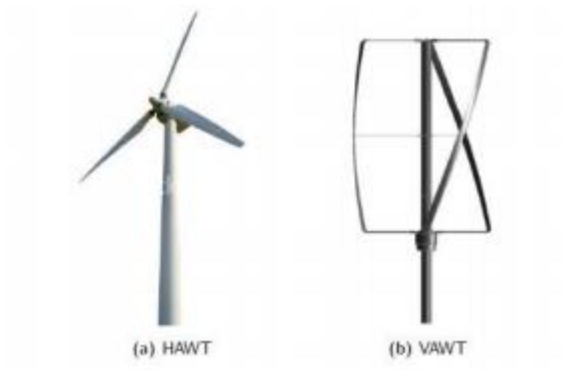


Figure 22 (a) HAWT 3 blade turbine and (b) VAWT turbine. Source: Kumara, E., et al. (2017). "Overview of the vertical axis wind turbines." Int. J. Sci. Res. Innov. Technol 4: 56-67.

Focusing on the modern 3-bladed offshore HAWT, its main components include the rotor, nacelle, and tower. The rotor includes the three blades which generators aerodynamic torque from the wind, the steel casted hub in which the three are bolted into and protected by a fiberglass cowl, the spinner, and a pitch bearing system. The pitch bearing system allows the blades to turn or pitch to different angles in order to capture the variation in wind. The nacelle is a fiberglass tube which consists of the drivetrain that converts the aerodynamic torque that comes from the hub through the low-speed shaft. The low-speed shaft is held by the main bearing which allows for smoother rotation. The low-speed shaft is connected to the gearbox and it converts the rotation from low to high speeds through the high-speed shaft that goes into the generator. On the high-speed shaft there is also a mechanical brake for breaking the turbine at standstill. The entire nacelle drivetrain on top of the tower can also turn into the wind direction using yaw drives. Typically, there is an anemometer and wind wave attached at the back of the nacelle used to measure the speed and direction of the wind. The anemometer is connected to a controller which automatically starts or stops the turbine when reaching its cut-in or cut-off speeds. The generator is connected to power electronics consisting of the converter and transformer. Lasty, the tower is typically made of steel and is mounted into the foundation (Norwea, 2018)

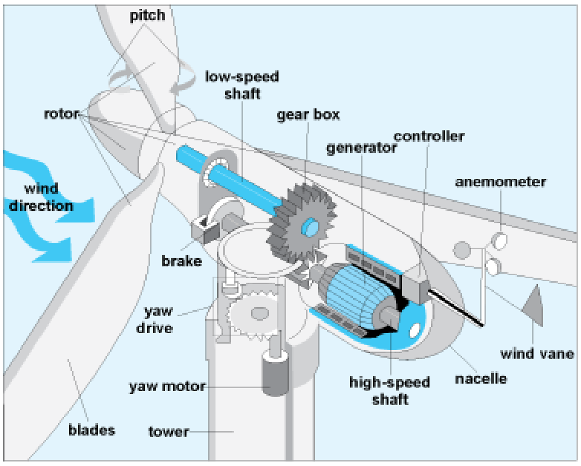


Figure 23 Main components of an offshore wind turbine. Source : Flumerfelt, R. W., & Wang, S. S. (2020). Wind power. Access Science. Retrieved November 2, 2020, from https://doi.org/10.1036/1097-8542.746400

OW turbines have grown rapidly in size over the past ten years following technological advances and calls to lower project costs. Nearly twice as big as onshore turbines, the average turbine size installed in OWF increased from 3MW in 2010 to 5.5MW in 2018 (IEA, 2019a). Future OWFs are expected to include much larger turbines in order to capture more power output per turbine and help lower overall costs. OW turbines make up between 30-40% of the upfront capital cost, however larger turbines lower the entire project costs due to lower maintenance and cabling cost (IEA, 2019a). For an example, Equinor and its partner SSE Renewables have recently chosen the 13MW GE Haliade-X turbine for their 3.6GW OWF Dogger Bank which is expected to start construction in 2021 (Equinor, 2019) . According to Stephen Bull (2020) at Equinor, one swept turn of the GE Halide-X rotor can power a home for two days. The 13MW Haliade-X turbine was recently eclipsed by Siemens Gamesa announcement the world's largest 14MW 14-222 DD model, with a prototype of the model expected to be installed in Denmark by fall 2021 (Parnell, 2020). Looking further ahead into 2030, the industry expects 15-20MW commercially available turbines for the offshore sector (IEA, 2019b).

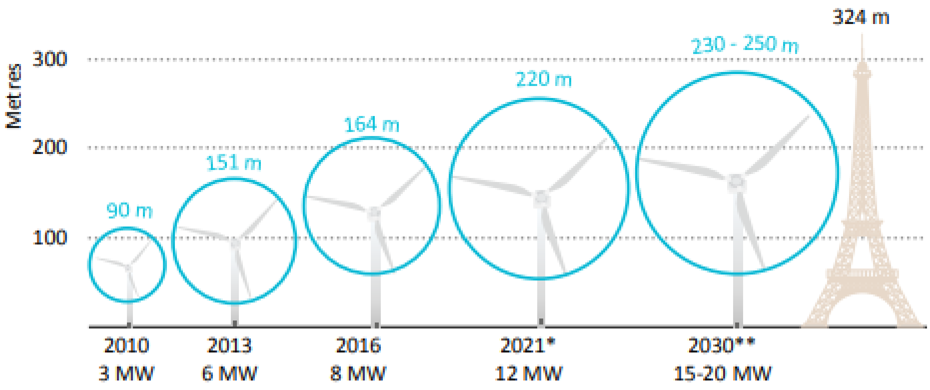


Figure 24 Evolution of offshore wind turbine size. Source: IEA (2019). "Offshore Wind Outlook 2019." World Energy Outlook Special Report. Retrieved 8/11, 2020, from https://webstore.iea.org/download/direct/2886?fileName=Offshore_Wind_Outlook_2019.pdf.

2.2.3 Array Cables

Array cables connect all the individual turbines to form a network which eventually aggregates the electricity and feeds it into to the offshore substation. These are buried into the seabed for protection and the length depends on an OWF turbine size and spacing, but typically between 1-2 km cable length for each turbine. The majority of developed OWF have installed cables with ratings at 33-36kV although developers are increasingly installing the newer 66kV cabling to reduce electric losses further. (Musial et al., 2019) According to BVG BVG Associates (2019a), 50% of new OW turbines in Europe will be connected at 66 kV by 2021.

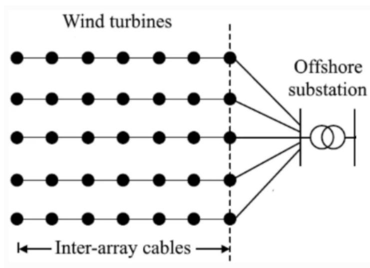


*Figure 25 Inter-array cable. Source: Rentschler, M. U., et al. (2020). "Parametric study of dynamic inter-array cable systems for floating offshore wind turbines." Marine Systems & Ocean Technology **15**(1): 16-25.*

Generally, electrical array cable cost increases with turbine spacing but decrease with turbine size. Thus, the exact turbine spacing is a trade-off between wake losses and array cable cost (Gould, 2014).

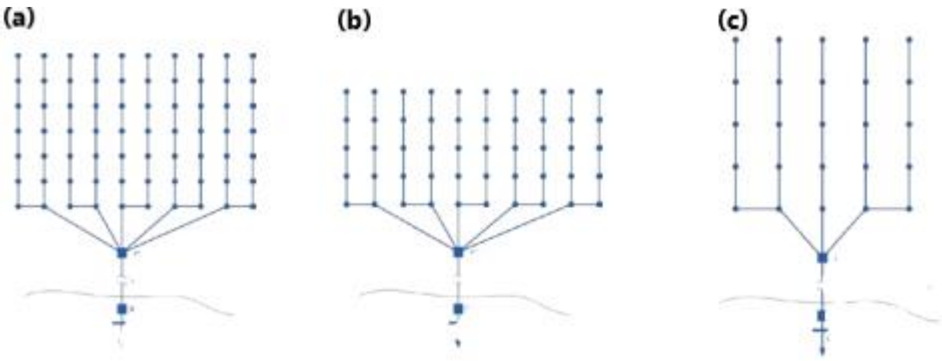


Figure 26 Illustration showing the trade-off between wake loss and array cable cost. In (a), OWF with 3.6MW turbine covering an area of 40km^2, in (b) 5MW turbine covering area of 36km^2, in (c) 10MW turbine covering area of 33km^2. All three OWF provide similar 250MW installed capacity, but with increasing turbine sizes there is need for less array cables but more spacing between turbines to reduce wake loss. Source: Gould, I. B. (2014). "Offshore Wind Plant Electrical Systems." Retrieved 3/11, 2020, from https://www.boem.gov/sites/default/files/about-boem/BOEM-Regions/Pacific-Region/Renewable-Energy/6-Ian-Baring-Gould---BOEM-Offshore-Wind-Plant-Electrical-Systems-CA.pdf.

2.2.4 Offshore substation

By stabilizing and maximizing the voltage of power generated by the turbines, reducing electrical losses, and transmitting the electricity to shore, offshore substations help maximize the electrical output. There are two technologies behind offshore substations, high-voltage alternating current systems (HVAC) and high-voltage direct current systems (HVDC) (Fernández-Guillamón et al., 2019).

HVAC systems converts and transmit electricity to an onshore substation through AC submarine cables. The substation increases the voltage level from the OWF to a transmission voltage level at 132-400 kV (Fernández-Guillamón et al., 2019).

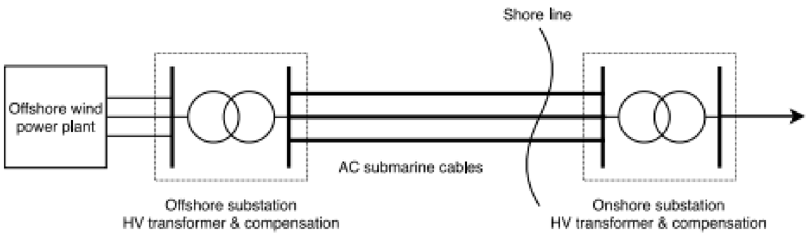


*Figure 27 HVAC transmission system overview. Source: Fernández-Guillamón, A., et al. (2019). "Offshore wind power integration into future power systems: Overview and trends." Journal of Marine Science and Engineering **7**(11): 399.*

On the other hand, in HVDC systems electricity is transformed from Alternating Current (AC) to Direct Current (DC) in converter stations and once the electricity reaches shore it is converted back to AC. Some offshore wind farms have used up to 400 kV DC and this standard is increasingly used for future planned OWF (BVG Associates, 2019a).

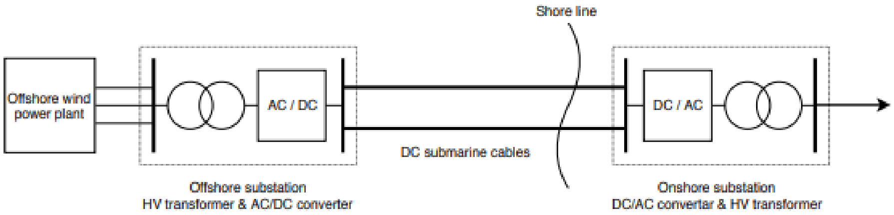


*Figure 28 HVDC transmission system overview. Source: Fernández-Guillamón, A., et al. (2019). "Offshore wind power integration into future power systems: Overview and trends." Journal of Marine Science and Engineering **7**(11): 399.*

Comparing the two systems, HVAC systems have comparatively lower costs, although over longer distances this system becomes more inefficient and therefore uneconomical. To address this issue, high voltage direct current (HVDC) transmission systems have been implemented, allowing the longer transportation of electricity with minimal losses. According to Fernández-Guillamón et al. (2019), HVDC systems are economically preferred over HVAC systems at distances between 50-80km from shore. HVDC systems have higher capital cost compared to HVAC system due to the need for converter stations, but as distances from shore reach 50-80km it becomes more cost-effective to choose HVDC system due to lower transmission losses and decreased cable cost from lower use of conductor material.

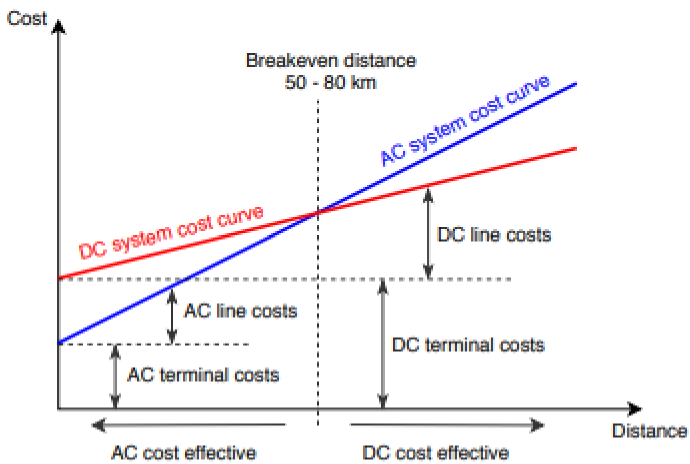


*Figure 29 HVAC and HVDC costs based on transmission distances. Breakeven distance is between 50-80km from land, at this point HVDC system becomes more economical. Source: Fernández-Guillamón, A., et al. (2019). "Offshore wind power integration into future power systems: Overview and trends." Journal of Marine Science and Engineering **7**(11): 399.*

The most powerful offshore HDVC converter station is the Dolwin beta, located in the North Sea. The Dolwin beta is connected to wind farms with AC cables but converts the electricity to DC in order to transmit electricity through a 45km long sea cable system before being converted back to AC on an onshore HVDC station (ABB 2015). Looking ahead, it would be necessary to develop a meshed offshore HVDC island grid that would be able to equip entire regions, such as in Europe, with electricity. The current HVDC technology only handles two connection points, thus innovation is required for future HVDC structures to handle the capacity of multiple OWF located in different areas. As transmission costs are expected to account for nearly one half of the total costs for an OWF, an island super grid would help significantly reduce costs (IEA, 2019a). One such initiative is the North Sea Wind Power Hub consortium which aims to create several islands hubs in the North Sea which connects OWF with bordering North Sea countries using the HVDC multi-connection system. In addition, on these hub islands it would be able to able to convert excess power to hydrogen production through electrolysis (Fernández-Guillamón et al., 2019).

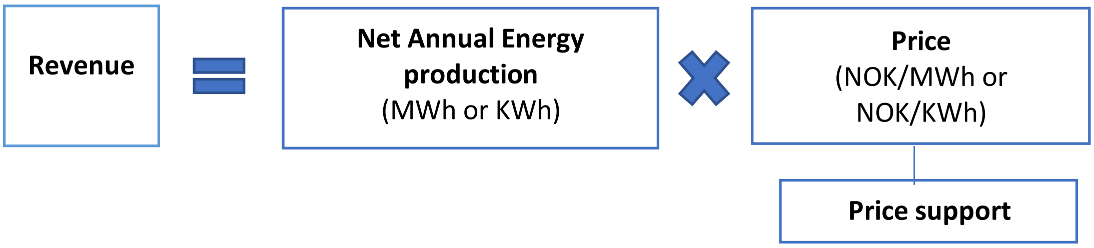
Figure 30 Vision for North Sea Wind Power Hub. Offshore wind farms in North Sea are connected to artificial hub islands, enabling multi country connection points for electricity transmission through HVDC stations (yellow lines) and production of hydrogen from excess power which can be transported through pipes (blue lines). Source: North Sea Wind Power Hub. (2019). Retrieved 3/11, 2020, from https://northseawindpowerhub.eu/key-players-wind-industry-support-ex-amination-feasability-of-north-sea-wind-power-hub/.

2.3 Economics and cost drivers

This section will describe the different revenue and total life cycle cost factors for an OWF which will determine its economic viability. On the cost side there are mainly development cost, investment/capital cost, operation and maintenance cost, and decommissioning cost (BVG Associates, 2018). The revenue from a wind farm has two main components: energy production and the price of energy. There are also some common tariff mechanisms and other financial incentives that are applied to wind energy including feed-in, tendering, and green certifications (Winje et al., 2020). Such incentives and policies can improve the economic feasibility of an OWF by reducing investments costs or increase revenue.

2.3.1 Revenue

The yearly revenue of an OWF is related to its annual energy production (AEP) and the price of the power sold into the market, which can also be further supported by financial incentive schemes.



2.3.1.1 Gross and Net Annual Energy Production

The annual energy production (AEP) was mathematically derived in equation (8). It is calculated by multiplying the turbine power curve from the power curve of wind speed V_i with the probability distribution function, and the number of hours in a year (Adaramola, 2019). By aggregating the AEP from each turbine in an OWF, the total AEP can be estimated in kWh/MWh/GWh. For a proposed project, the AEP calculation must be estimated or simulated since there is no actual OWF to provide the real figure.

It is important to differentiate between gross and net AEP. The gross AEP is the predicted estimation which excludes any losses, whilst net AEP is an adjusted figure that is less than the gross AEP (BVG Associates, 2017). This adjustment is due to several wind farm losses such as curtailment of the grid, losses in transmission, equipment condition, weather, blade damage, downtime for maintenance, etc (Barber, 2017). In other words, the net AEP is the actual power delivered to the public grid and sold at market prices. Therefore, when calculating the yearly revenue, we need to consider the net AEP (Barber, 2017).

2.3.1.2 Power price

The power price is determined by the market equilibrium between supply and demand. With lack of storage capacity, supply and demand of electricity supply and demand must be the same at each point of time.

There are several supply and demand driving forces that affect the power price in both short run and long-run in Norway. In the short-run, prices can vary due to temperature, wind, precipitation, price differences between Norway and other connected countries, etc. In the long run, prices can be determined by climate policy, expanding transmission capacity to other countries, climate change, economic growth, energy efficiency improvements, etc. (Hagem, 2020)

The physical power is traded at the Nordic power exchange Nordpool. Power producers can also hedge their project risk using future contracts in which financial settlement is made but no physical power is delivered (Johansen, 2019). At this exchange, Norway is divided into five price areas due to bottlenecks in the main grid and prices can vary from hour to hour. The power producers will offer the amount of power and price for each hour in the next 24 hours, and this is then matched at the exchange by the power distributors, eventually creating a market equilibrium price for each hour in the entire region. (Norwea, 2018)

Figure 31 Five price areas in Norway. Statnett (2020). "Langsiktig markedsanalyse: Norden og Europe 2020-2050." Retrieved 24/11, 2020, from https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/2020-langsiktig-markedsanalyse-norden-og-europa-2020-50.pdf.

Power producers can either sell the power at spot prices or secure long-term prices through power purchase agreements. Spot prices vary hour from hour and gives direct exposure to the fluctuations in power prices. This creates uncertainty and risks for a power producer who might face depressed power prices. In order to reduce this risk, the power producer can enter into a power purchase agreement (PPA) with a counterparty (Norwea, 2018). There exist many variations, but in general a PPA is a contract between two parties where the producer will provide an agreed volume of power directly to a buyer at a fixed price and time. The buyer will benefit by locking in an amount of renewable energy at competitive prices, while the producer will benefit in terms of reducing price risks. This is especially beneficial for intermittent power producers such as offshore wind who are dependent on a predictable revenue stream and in terms of financing from financial institutions (Koch, 2020). The use of PPA for wind power has been increasing in Norway, with companies such as Facebook, Google, Hydro, and Elkem entering PPA with onshore wind producers (Hovland, 2020).

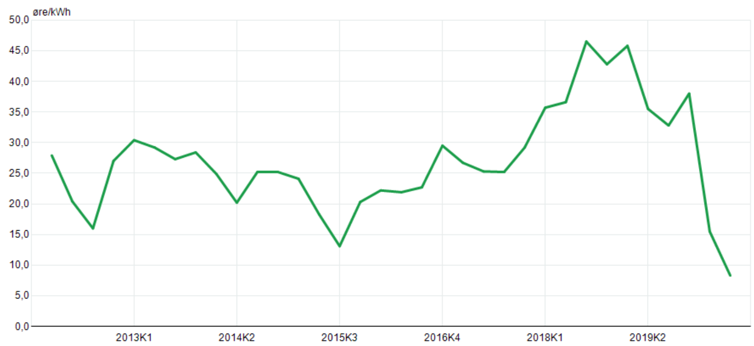


Figure 32 Development in Norwegian wholesale power prices between 2012-2020 in øre/kwh. In this market power producers, power suppliers, and other actors can buy and sell power. Source: SSB https://www.ssb.no/statbank/table/09363/chartViewLine/

2.3.1.3 Price Support policies

Most forms of renewable energy need financial support mechanisms. Governments can have different objectives when designing a renewable energy policy instrument, but the primary goal is to stimulate renewable energy production. To this end, it is important to reduce the risk of investing into capital-intensive renewable energy systems such as OWF. This can be done in various ways, but financial support policies can be divided into investment-based or production-based (OEE, 2019). Investment-based policies are typically subsidies, tax incentives, accelerated depreciation, and favourable loans. Production-based can be further divided into quantity-based and price-based schemes (OEE, 2019). Since this section is describing the revenue, we will be looking at the main production-based tools currently implemented in the OW industry. This includes green certificates, contracts for differences, and feed-in-tariffs.

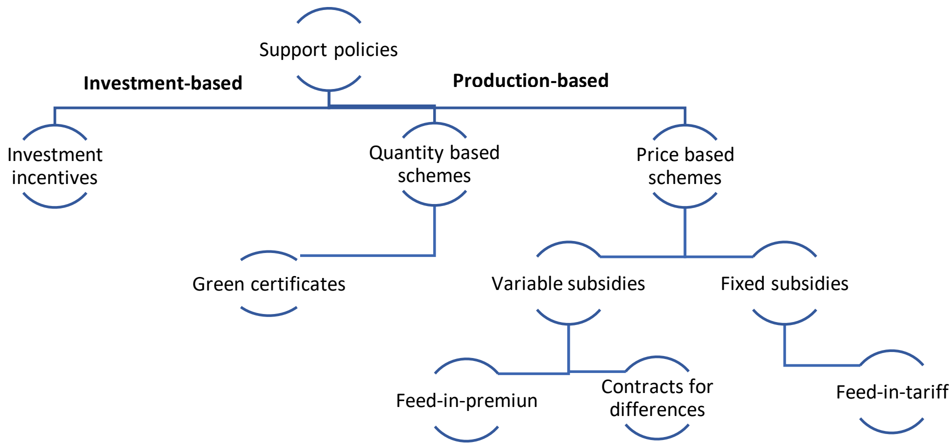


Figure 33 Overview over main policies. Authors own.

The fixed feed-in tariff (FIT) provides a fixed support price for each kWh/MWh of power that is put into the grid by the OWF for a predetermined period. This fixed price system of electricity provides investors, banks, and developers with long-term certainty over a projects future revenue stream. Consequently, more projects will be realized and this scheme was instrumental in developing renewable energy projects in the 1990s and 2000s. The problem with FIT is that it is an expensive system to maintain by the governments. Moreover, FIT can drive too much renewable energy development too fast. Critics have also argued that governments should not set the prices, this needs to be done by the competitive market (OEE, 2019).

Feed-in premiums (FIP) is a more market-oriented approach price support mechanism than (FIT). In a FIP system, the producer is guaranteed a fixed premium on top of the variable spot power price for a predetermined period. If the market price goes up, so too does the remuneration and vice versa. Thus, the FIP revenue is only a portion of the total revenues obtained by the project, the rest are derived from the direct market sale. The main benefit with this system is that it is well integrated with liberalized power markets whilst also providing some price support for producers. The disadvantage is less investment certainty compared to the FIT system. There also exists other variations of the FIP system such as variable premium model with caps and floors (OEE, 2019).

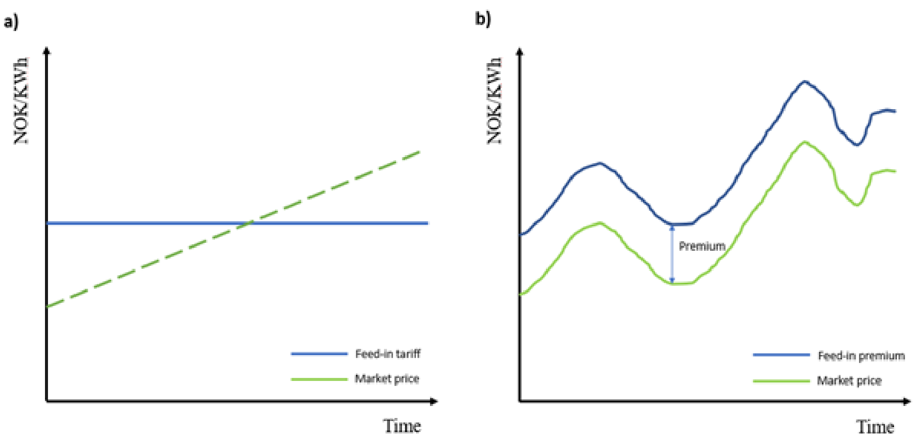


Figure 34 Fixed feed-in tariff shown in a) and Feed-in premium shown in b). Authors own

Contracts for difference (CfD) is a contract based on an agreed "strike price" between the generator and the off taker. If market prices are below the strike price, the generator receives the "top up." On the other hand, if the market prices are above the strike price, the generator must pay back the difference (Evans, 2019). Essentially, this system provides revenue certainty against downside risk, but it takes away the potential upside windfall profits if prices go above the strike price. Another added benefit is reduced policy costs for the government if prices skyrocket (OEE, 2019). In EU it is common to have a competitive auction based CfD system. In the auction, each developer will place a bid in a specific area for their required project strike prices. The lowest bid will win the strike price support for the specific area. Thus, this system adds a competitive feature to the CfD system, incentivising developer to reduce costs (Ueland et al., 2019).

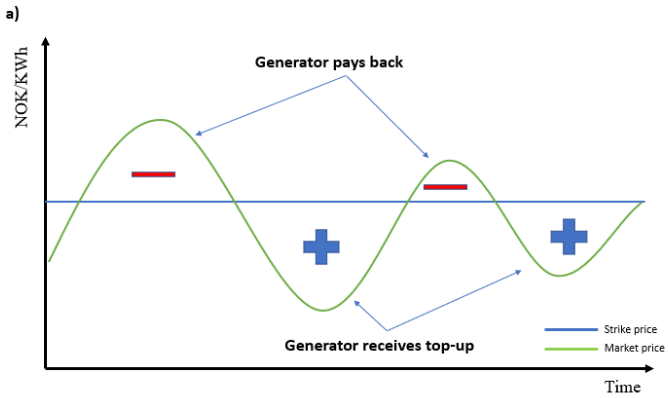


Figure 35 Contracts for difference. Authors own

The green certificate system is slightly more complex system. Renewable energy sellers receive tradeable green energy certificates for every MWh they produce. These certificates can then be sold to a buyer in the certificate market. Buyers might typically be power providers who are obliged to buy a certain amount of renewable power but are unable to because of geographical constraints or contractual issues. In this way, there is a market of buying and selling these green certificates which provide the renewable energy producer with additional revenue. This system will therefore provide incentives to renewable energy producers to produce more, but has been criticized for “green washing” a buyers activities (OEE, 2019).

Table 3 summarizes the various price support tools for OW currently implemented in European countries. As can be seen, CFD and FIP system are dominating the European OW landscape. As previously mentioned, each price support tool can come in various shapes and forms. For an example, the CfD system in Finland is slightly different to the CfD system in UK through certain additional rules. In addition, some countries might have additional support tools in combination with a price support system. This can be seen in Lithuania where the OW developers have a CfD system, investment grants, and low-rate loans. According to Winje et al. (2020), the trend for European countries is moving towards CfD system due to its cost-effectiveness. The German OW industry is amongst others currently pressuring the government to implement this system.

Table 3 Current Support structures for offshore wind in various countries. Source: Winje, E., et al. (2020). "Virkemidler for å realisere flytende havvind på norsk sokkel." Menon publikasjon(116)

Country	Price support mechanism
Norway	Green certificates, discontinues in 2021
Sweden	Green certificates, extended till 2030
Denmark	Contracts of difference (CfD)
Finland	Contracts of difference, investment grants
United Kingdom	Contracts of difference (CfD)
France	Contracts of difference (CfD)
Germany	Feed-in-premium (FIP), low rate loans
Netherlands	Feed-in-premium (FIP)
Belgium	Feed-in-premium (FIP), investment grants
Lithuania	Contracts of difference (CfD), low-rate loans, investment grants

Norway will discontinue its green certificates system after 2021 in order stabilize falling power prices (Meld. St. 25 (205-2016)). Currently, after 2021 there will be no price support mechanisms for OW development. The industry is currently lobbying the government for more support in order to develop a home market for OW. However, support through taxpayer money might be difficult for the Norwegian government to justify since there is ample power in the country. Although the Minister of Petroleum and Energy, Tina Bru, recently called for more support to the industry, any future price support mechanisms for OW in Norway is yet to be determined (OED, 2020a). Currently, the only support mechanism for OW development in Norway are investments grants through Enova, where Aker Offshore Wind was recently granted NOK 10 million for research projects within floating wind (Christensen, 2020).

2.3.2 Cost

The main cost components for an OWF can be grouped into capital costs (CAPEX), operating and maintenance cost (OPEX), and decommissioning cost (DECEX). Like other renewable energy systems, such as hydro and solar, OW projects have high up-front capital investment cost but low OEPX cost since there are no fuel cost. Figure 25 below provides the reader with an overview of the main elements in each over the lifetime of an OWF. This section will intend to give the reader a brief description of each.

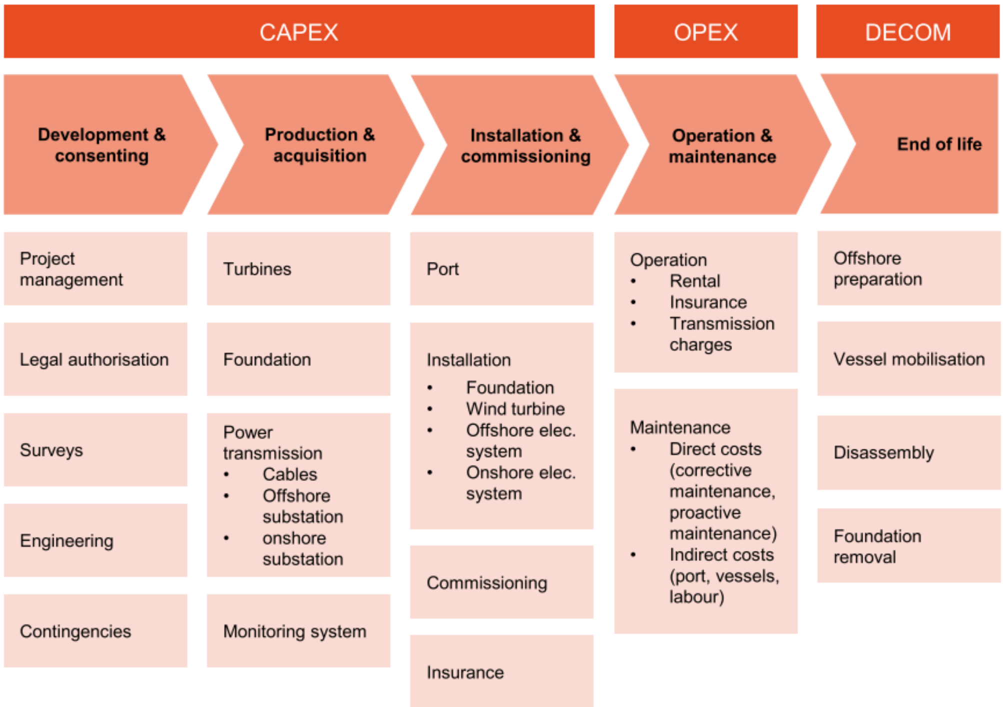


Figure 36 Overview of cost breakdown of an OWF over different stages of the OW life. Source: Bosch, J., et al. (2019). "Global levelized cost of electricity from offshore wind." Energy ***189****: 116357.*

2.3.2.1 CAPEX Cost

As figure 35 illustrates, CAPEX cost is divided into a series of major items relating to the development of a project, production and installation. Upfront CAPEX cost for a project will indeed depend on the choice of site, water depth, distance from shore, number of turbines, and innovations. The relative share of each cost component will thus vary from project to project. According to Bosch et al. (2019), CAPEX cost can be expressed as:

$$CAPEX_i\left[\frac{1}{MW}\right] = C_{dev.,i} + C_{turb.,i} + C_{found.,i}(d) + C_{trans.,i}(D) + C_{ins.,i}(D) + C_{decom.,i}$$

Where development costs and turbine costs, $C_{dev.,i}$ and $C_{turb.,i}$ respectively, are solely dependent on wind farm capacity. The foundation costs ($C_{found.,i}$) are dependent on water depth (d). Furthermore, transmission cost ($C_{trans.,i}$) and installation cost ($C_{ins.,i}$) depend on distance (D) to the nearest coastline. Finally, decommissioning cost ($C_{decom.,i}$) are included in the CAPEX cost as a proportion of installation costs which is logical because DECEX cost are simply the reverse process of the installation phase. This provides us with the main CAPEX components and how they depend on certain factors such as depth and distance (Bosch et al., 2019).

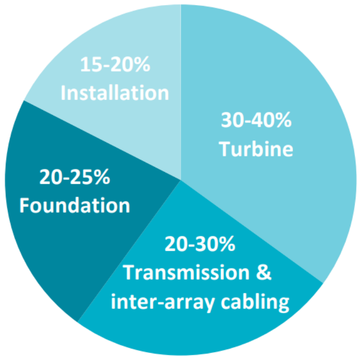


Figure 37 Breakdown of CAPEX for OW projects completed by 2018. Source: IEA (2019). "Offshore Wind Outlook 2019." World Energy Outlook Special Report. Retrieved 8/11, 2020, from https://webstore.iea.org/download/direct/2886?fileName=Offshore_Wind_Outlook_2019.pdf.

2.3.2.1.1 Turbine

The OW turbines generally represent the lion share of the CAPEX cost for projects. As stated by IEA (2019b), the turbines accounted for 30-40% of the total CAPEX project cost for typical bottom-fixed OW project completed in 2018. With turbine sizes expected to grow further for future projects, this percentage share will likely grow or at least remain the dominant share. The turbines are a critical component of an OWF since it is the technology that generates the power. Therefore, developers will not act sparingly when it comes to choosing the turbine technology. However, cost reductions are likely to be made through economies of scale as projects become larger. Turbine manufacturers are also focusing on using lighter and more resilient materials such as carbon fibres and glass for the rotor blades, helping improve aerodynamics and extending the lifetime. Further improvements are expected due to the competitive nature in the industry where the top turbine manufacturers Siemens, Vestas, GE, and Enercon compete for market share. It is also worth mentioning that by increasing the turbine size it has an effect of reducing the number of foundations and as previously discussed, the length of inter-array cables. This effect will in turn reduce installation and OPEX cost as there are fewer turbines (IEA, 2019b).

2.3.2.1.2 Transmission system & inter-array cabling cost

The next most expensive CAPEX item of an OWF are transmission system and inter-array cabling, typically constituting between 20-30% of the of the total CAPEX cost (IEA, 2019b). This cost is dependent on the distance to the onshore grid connection, the wind farm layout, and the transmission technology used (Thema Consulting, 2020). Cost reductions can be made here if governments agree to cover some the transmission cost, something the industry is pushing for as projects go further out to sea. Furthermore, OWF close to each other could possibly agree to share the cost for a common connected transmission system.

2.3.1.1.3 Foundation cost

The OW turbine foundation is not far behind the transmission and inter array cabling cost, making up between 20-25% of the total (IEA, 2019b). Monopile foundations are currently deployed in around 82% of the OW projects in Europe, but as future projects move further into deeper waters it becomes more economically feasible to use floating foundation technologies in order to reduce steel materials. The floating foundation technologies are obviously costly in their pre-commercial phase, but costs are expected to fall further through technology learning. Thus, the CAPEX cost of foundation depends on the concept, seabed conditions, and the water depth (Thema Consulting, 2020).

2.3.1.1.4 Installation cost

The last major CAPEX component for OWF is the installation cost, which make up between 15-20% of the total. Different specialized vessels are used to transport and install the foundations, turbines, substations and cables. Furthermore, the specialized vessels for installing bottom-fixed OWF are different from the vessels used for installing floating OWF. Day and long-term rates for these ships depend on their availability, hence developers will try to lock in long-term charter contracts to control costs. It takes an average of two to three days to install a turbine and about three to five days to install a foundation (Thema Consulting, 2020). According to Thema Consulting (2020), the current availability of specialised jack-up crane vessels are in scarce supply, and therefore command high day rates. On the vessel supply side, it is challenging for vessel owners to plan the technical capacity of future installation vessels since the turbine sizes are growing at a faster rate than expected. However, technology cost reductions and improved streamlined processes have led to significant reductions in installation costs. Further cost reductions are to be expected in the future as a larger fleet of suitable installation vessels enter the market, but the cost reduction will be more modest compared to the reductions in turbine and foundations costs (Thema Consulting, 2020).

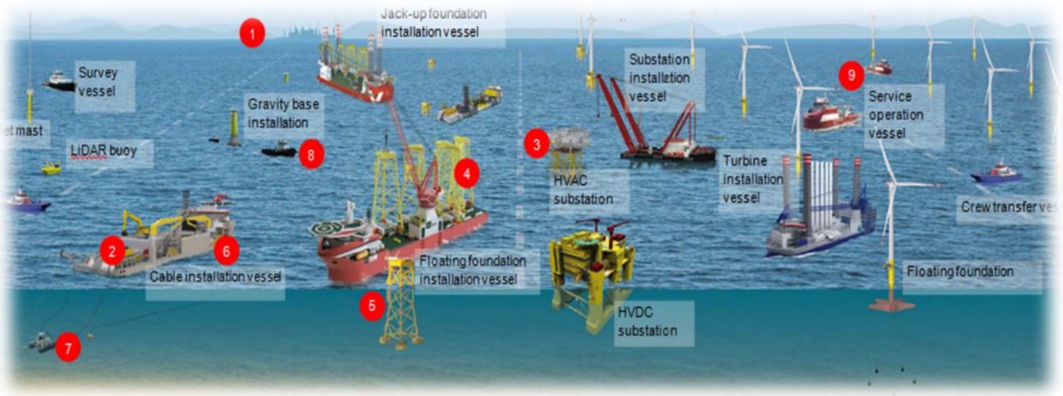


Figure 38 Specialized installation vessels for OW. Source: Ottesen, D. (2018). "Gobal Offshore Wind Market Report." Retrieved 8/11, 2020, from https://www.norwep.com/content/download/33129/241197/version/1/file/Global+offshore+wind+market+report.pdf.

It is also worth mentioning that DECEX cost constitute approximately 6.8% the total CAPEX but is in this case included in the installation cost of 15-20% of the total. Decommissioning involves the removal of all the OWF structures after the project life has ended. Structures such as the substation and export cables could be repowered and therefore reused on site, while other components will be salvaged and recycled. There could also be some revenue obtained from the sale of scrap materials. Composite materials in the blades are currently not recyclable but there are innovative processes exploring this issue. Developers typically place this the DECEX cost within the installation cost bracket as decommissioning is simply the reverse order of the installation process (BVG Associates, 2019b).

2.3.1.1.5 Development and consenting cost

Development and consenting cost make up only 2.5% of the total CAPEX. This includes cost for site investigations, environmental studies, project management, consultants, engineering, legal, and license applications. In the early development phase, developers carry out geotechnical and geophysical studies of potential sites to identify the seabed, which is used to optimize the layout of the OWF. An Environmental Impact Assessments of the potential OWF is also carried out according to law. It is often required to use external consultants for such studies and thus comes at a cost (BVG Associates, 2019b).

2.3.1.1.6 CAPEX cost per MW

According to (IEA, 2019b), a 250MW OWF project has on average upfront CAPEX cost of around $1 billion, which amounts to approximately NOK 9.2 billion. On a CAPEX cost per MW, this amounts to NOK 36,8 million/MW. CAPEX data obtained from Norwep (2020) on various OW projects in Europe are shown in table 4, and show that CAPEX cost per MW for these are not too farfetched from the IEA estimates. The CAPEX costs for each project will obviously vary in terms of the year developed, water depth, distance from shore, capacity size, etc. The data does prove the staggering amounts of capital that are needed to invest in such OW projects. The CAPEX cost for the Dogger Bank project is expected to be in the region of NOK 108 billion, but the sheer size of the project will in turn lower the CAPEX cost per MW compared to smaller sized projects (Equinor, 2019). Such massive upfront capital investment costs are likely to continue as developers seek larger projects to fully utilize economies of scale.

Table 4: CAPEX cost for bottom-fixed large offshore wind farms in Europe. Authors own. Data obtained from Norwep (2020). "Projects." Retrieved 8/11, 2020, from https://wind.norwep.com/projects.

Name	Location	Depth / Distance from shore	Capacity	No. of turbines	Total CAPEX cost	CAPEX cost per MW
Horns Rev	North Sea, Denmark	6-14m / 18 km	160 MW	80	MNOK 1,465	9,162,247 NOK/MW
Horns Rev 3	North Sea, Denmark	10-21m / 29-44 km	407 MW	45	MNOK 10,920	26,831,143 NOK/MW
Amrumbank West	North Sea, Germany	19-24m / 35-40 km	302 MW	80	MNOK 10,852	34,934,105 NOK/MW
Hohe See	Germany, North Sea	26-40m / 90-104 km	497 MW	71	MNOK 19,656	39,550,293 NOK/MW
Dogger Bank	United Kingdom	20-35m / 130-190km	3600 MW	285	MNOK 108,457	30,127,023 NOK/MW

2.3.2.2 OPEX Cost

Whilst CAPEX costs contribute to most of the cost during the initial phase of a wind farm, OPEX cost gradually take over the as the wind farm ages. OPEX cost are incurred after the completion of an OWF to the beginning of decommissioning (IRENA, 2016). While OW benefits from having zero fuels costs, they do have to consider other OPEX cost including operations & maintenance (O&M), inspections, insurance, transmission charges to national grid, and administrative cost.

A literature review carried out by Crabtree et al. (2015) summarized the findings of several studies on OPEX cost for a typical OWF. In addition to finding that OPEX constitutes between 25-40% of the total lifetime costs, the author also recognizes that O&M cost make up around 50% of the total OPEX cost. It shows that maintenance and repair work on wind turbines make up a considerable share of the total OPEX cost since these assets need regular supervisions in order to function properly. This requires vessel operations, staff, spare-parts, port fees, and system monitoring tools. IRENA (2016) also acknowledges that O&M cost make up around 50% of the total OPEX cost, thus confirming that O&M are a critical piece of the pie. Other costs which are included in OPEX can include insurance fees, transmission charges to the national grid, or license fees (Crabtree et al., 2015). OPEX cost will therefore be project specific and vary depending on where the OWF are located.

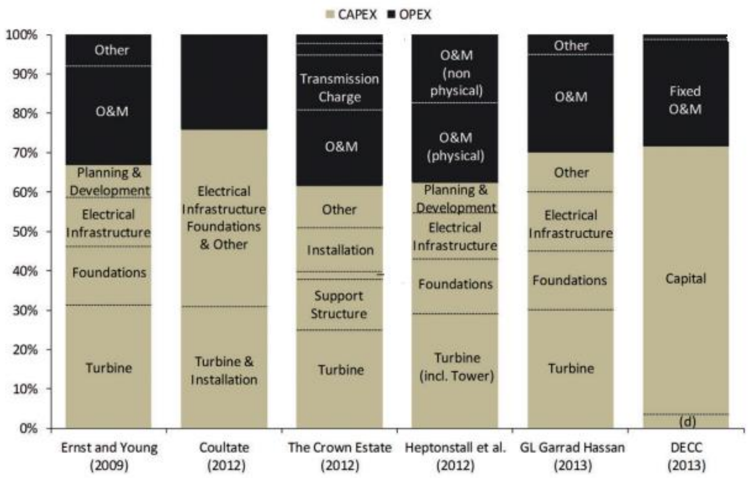


*Figure 39 OPEX. Source: Crabtree, C. J., et al. (2015). "Wind energy: UK experiences and offshore operational challenges." Proceedings of the Institution of Mechanical Engineers, Part A: Journal of Power and Energy **229**(7): 727-746.*

Companies are reluctant to share their OPEX cost which makes it difficult to find data. However, the industry is working on innovative tools to bring down O&M costs. Drones and other remote offshore vehicles are particularly useful when performing inspections on OWF, which reduces the use of expensive vessels. Sensors attached to the turbine, foundation, cables, and other substructures can with the use of artificial intelligence detect and predict anomalies in these assets, helping avoid production loss and prevent unplanned repair work. These technologies are currently developed by 4subsea and Aker's Cognite on top of their software management tools.


Figure 40 Drones and sensors with artificial intelligence to reduce OPEX cost. Source image left: Lillian, B., 2020. Drones Inspect Entirety Of 317 MW Statoil Offshore Wind Farm | North American Windpower. [online] Nawindpower.com. Available at: <https://nawindpower.com/drones-inspect-entirety-317-mw-statoil-offshore-wind-farm> [Accessed 9 November 2020]. Source image right: Skoljak, N., 2020. 4Subsea Studying Digital Twin Cost-Reduction Potential In Offshore Wind | Offshore Wind. [online] Offshore Wind. Available at: <https://www.offshorewind.biz/2020/05/01/4subsea-studying-digital-twin-cost-reduction-potential-in-offshore-wind/> [Accessed 9 November 2020].

2.3.2.3 Overall Cost Metric Measurement method: LCOE

2.3.2.3.1 LCOE components

LCOE is a practical method to determine the key cost factors for an energy generating plant. In order to lower the LCOE for an OWF it is thus important to reduce both the CAPEX and OPEX in the numerator, and/or increase the total energy output in the denominator. The central factors determining the LCOE for an OWF is illustrated by the blue boxes in figure 41. Thus, each blue box can play a role in reducing the LCOE for an OWF. The figure also illustrates how certain elements are linked. For an example, AEP can be raised by increasing the amount and size of turbines in an OWF. CAPEX cost per turbine would increase with larger turbines as the construction requires larger foundations. On the other hand, OPEX costs can be significantly reduced as O&M costs are lowered. The net effect is expected to reduce the LCOE (IEA, 2019b).

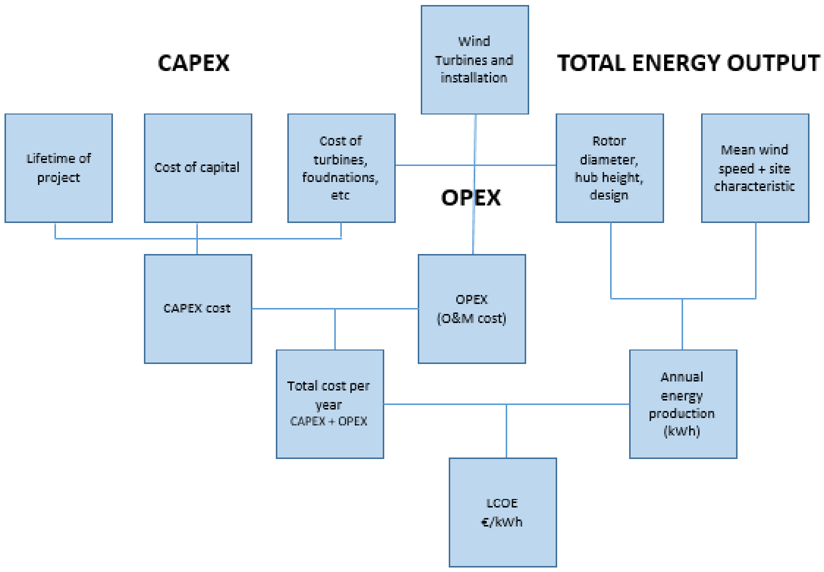


Figure 41 Cost breakdown LCOE. Authors own modification from source: EWEA (2009). "The Economics of Wind Energy." Retrieved 11/11, 2020, from http://www.ewea.org/fileadmin/files/library/publications/reports/Economics_of_Wind_Energy.pdf.

In the hunt for grid parity, the industry is looking for ways to improve every component of LCOE. As commented by Stephen Bull, who is Senior Vice President in in Equinor's New Energy Solutions business, the total lifetime of an OWF can be increased to 35-50 years, thereby squeezing out more energy output over its lifetime (Bull, 2020). With a current expected lifetime between 25-30 years, increasing the lifetime of an OW project to Stephen Bull's forecast can therefore help reduce LCOE significantly.

As laid out by of IEA (2019b), another significant component of LCOE for projects completed in 2018 is the cost of capital. Their analysis shows that nearly half of LCOE is attributable to cost of capital. Cost of capital can be seen in view of its weighted average capital cost (WACC), which includes both the cost of equity and cost of debt. The cost of debt can be seen as the interest charges, while the cost of equity is the rate of return required by investors (OEE, 2019). The higher the risk of an investment, the higher the return investors demand on their equity. With the world economy in a low-rate environment coupled with a maturing OW industry, WACC is likely to be lower for future OW projects, thereby driving LCOE further down.

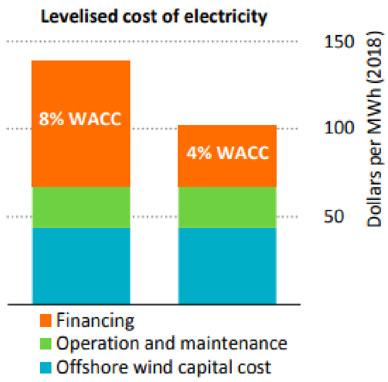


Figure 42 Cost of capital makes up nearly half of LCOE for OWF completed in 2018. Reducing the WACC from 8% to 4% would lower LCOE from 140$/MW to 100$/MW. Source: IEA (2019). "Offshore Wind Outlook 2019." World Energy Outlook Special Report. Retrieved 8/11, 2020, from https://webstore.iea.org/download/direct/2886?fileName=Offshore_Wind_Outlook_2019.pdf.

The study by Thema Consulting (2020) have current LCOE estimates in the range of 60-110 €/MWh for completed bottom-fixed OWF. Looking ahead, this range is expected to continue its downward trajectory through technology learning effects, further cost reduction, and increased output. By 2030, completed projects are expected to reach a level between 50-70 €/MWh (Thema Consulting, 2020). As calculated by BVG Associates (2019a), the current average LCOE for all pre-commercial floating OW projects lies at approximately 150 €/MWh, similar to where bottom fixed commercial projects were just a few years ago. The similarity in offshore water conditions means that floating OW can piggy-back on the recent innovations within the bottom-fixed industry. It is predicted that floating OW will make a similar downwards trajectory in LCOE and converge with bottom-fixed by 2035. For an example, Equinor has an ambitious target to reach a LCOE between 40-60 €/MWh for its floating OW projects within 2030 (Equinor, 2018).

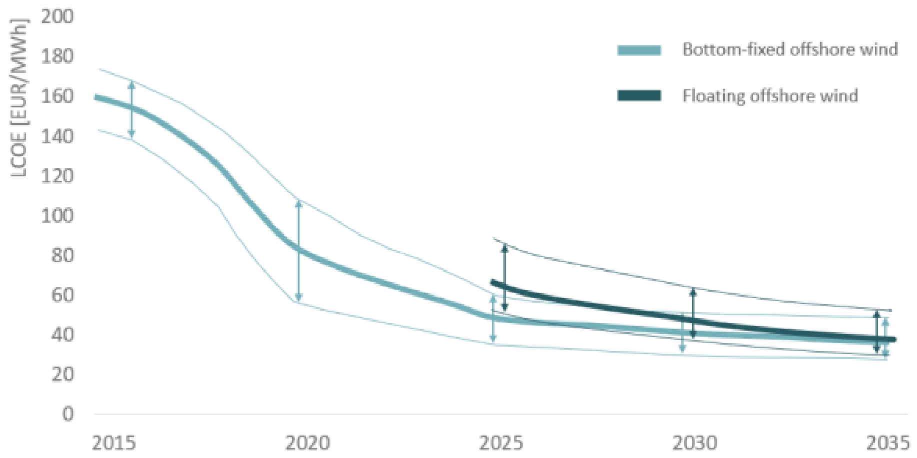


Figure 43 LCOE development of floating and bottom-fixed OWF. Source: Thema Consulting (2020). "Offshore Wind – Opportunities for the Norwegian Industry." Retrieved 8/11, 2020, from https://www.norwep.com/Market-info/Offshore-Wind-Opportunities-for-the-Norwegian-Industry.

The trajectory range for bottom-fixed OW projects is evident in the UK OW auction of 2019 where developers place competitive bids for their required OW project strike prices in the CfD system. In other words, the auction strike price represents the price level needed to cover the cost for developing and operating an OW project. The auction in UK witnessed a record low strike price of 45 €/MWh, awarded to Equinor and SSE Renewables' Dogger Bank bottom-fixed OW project (Evans, 2019). This pattern of lower strike prices is evident in other European auctions results, which can be seen in table 5. For some projects in Germany and Netherland there were auction bids towards zero, which means the developer believes the project can be profitable with income solely from the power market (Ueland et al., 2019).

It is worth mentioning that it is difficult to compare the strike prices between different EU countries as each country have implemented their own indirect support features. For an example, developers in Germany, Netherlands and Denmark do not bear the grid connection cost, helping reduce project cost. On the other hand, developers in the UK lack such indirect support and are required to bear the grid connection cost. In addition, the duration of the price support varies between countries. The price support duration in Denmark and Netherlands at respectively 12 and 15 years is much shorter than the duration of 20 years found in Germany. All else being equal, a developer will likely bid a higher strike price in a country with shorter price support duration. That said, the falling trend in strike prices for all EU countries demonstrates that total costs are expected to fall further (Winje et al., 2020).

Table 5 Auctions in different European countries show falling strike prices for OW. Authors own. Data obtained from: IEA (2019). "Offshore Wind Outlook 2019." World Energy Outlook Special Report. Retrieved 8/11, 2020, from https://webstore.iea.org/download/direct/2886?fileName=Offshore_Wind_Outlook_2019.pdf.

Project	Strike price (€/MWh)	Expected COD	Project	Strike price (€/MWh)	Expected COD
United Kingdom			**Germany**		
East Anglia 1	132	2020	Baltic Eagle	64	2023
Triton Knoll	83	2021	Gode wind 3	59	2024
Moray East	64	2022	**Netherlands**		
Hornsea 2	66	2022	Borselle I/II	73	2020
Dogger Bank	45	2025	Borselle III/IV	54	2021
Seagreen	47	2025	**Denmark**		
Sofia	41	2026	Horns Rev 3	103	2020
France			Kriegers Flak	50	2021
Dunkirk	44	2026			

3. Legal and regulatory

3.1 The Ocean Energy Law

The relevant law which regulates all renewable energy production outside of the Norwegian baseline and within the Norwegian economic zone is the Ocean Energy Law ("Havenergiloven"). The law establishes the legal basis for future development of renewable energy production at sea. Adopted in 2010, the law stipulates that the right to exploit renewable energy resources at sea belongs to the Norwegian Government. As defined in §1-4, renewable energy production includes the production of electricity by exploiting renewable resources such as wind, waves, and tidal waves. The law also applies to the transformation and transmission of the electricity at sea (Lovdata, 2010).

Referring to §2-2, it is required that the State opens ocean areas for renewable energy production before licenses applications can be submitted (Lovdata, 2010). This is to secure that the State can control and plan the development of renewable energy with a long-term, holistic approach. NVE's strategic assessment report has its background from §2-2 as the State used the expertise of NVE to find the most suitable areas for offshore wind. As a result, the State opened the area Sørlige Nordsjø II on June 12th, 2020 for offshore renewables, meaning it is possible and required to apply for a license for OW projects.

In accordance with §10-10 the State has the option to add regulations supplementing the Ocean Energy Law (Lovdata, 2010). At the same time as announcing the opening of the two areas, the State indeed approved a new regulation which will take effect on January 1st, 2021. The regulation, named Ocean Energy Regulation (Havenergiforskriften), provides the necessary steps and details for the licensing process.

The laws regulating the transmission and grid connection of electricity outside the jurisdiction of the Ocean Energy Law requires additional attention. In the case for an OWF, the electricity produced can be transmitted and connected to onshore facilities, petroleum installations, hydrogen production facilities, and/or exported to foreign states. As specified in §10-10 of the Ocean Energy Law, the export and import of electricity to a foreign state requires an additional license (Lovdata, 2010). Thus, the Ocean Energy Law opens the possibility for the developer to construct a transmission line from the OWF directly to a foreign country through a production radial. The Energy Law (Energiloven) regulates the production and distribution of electricity within the Norwegian baseline.

3.2 The Ocean Energy Regulation: Licensing process

The required steps to obtain a license for OW development is presented in the regulation. Figure 44 illustrates the entire license process for OW which will be described further below. The process mirrors the license process found for onshore wind, however there are certain differences. For instance, there are stricter deadlines in the process for OW. According to Ann Myhrer Østenby, senior engineer at NVE (conversation on 30th June 2020), the stricter deadlines were placed due to the "ketchup effect" experienced within onshore wind. Without deadlines, onshore wind developers delayed projects up to 10-15 years awaiting improved wind technologies, thus creating a ketchup effect of wind farms once all the wind farms became installed. This turned the public negative and hence the reason for stricter deadlines for OW.

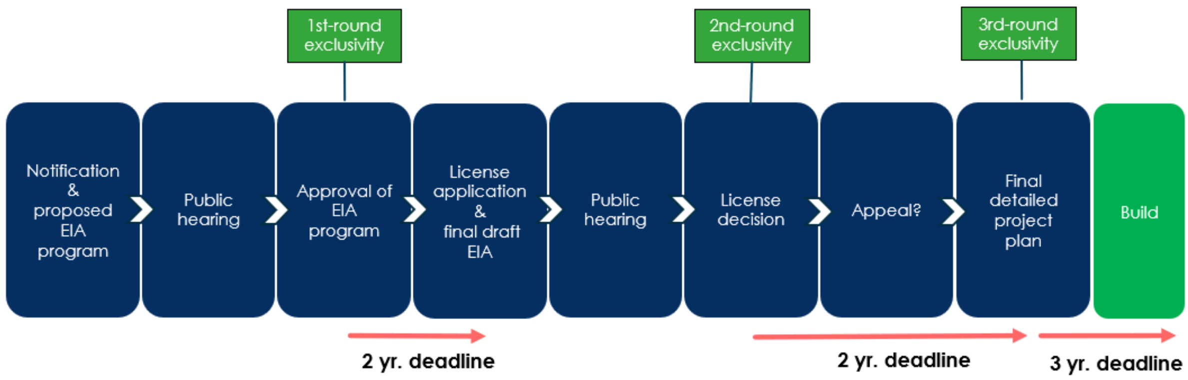


Figure 44 OW license application process. Source: Authors own

1. In the first step, the developer submits a **notification along with a proposed project-specific Environmental Impact Assessment plan (EIA)** to the Ministry of Petroleum and Energy (OED). The developer needs to submit the notification through

a legal Norwegian entity. The proposed EIA plan should at minimum depict a description of the energy project, expected costs, technology, development methods, possible environmental effects, and information about the developer's business activities. In addition, a case processing fee of NOK 100,000 must be paid to NVE for the notification to be processed further. OED can demand additional information from the developer if they deem this necessary (Lovdata, 2020a).

2. The proposed EIA plan is sent to a **public hearing** in the second step where the relevant authorities and interest groups can voice their opinions regarding the plan (Lovdata, 2020a). Relevant groups can for example be the military, fishery department, WWF, shipping industry, etc. The hearing committee will gather all the input and provide this to OED.
3. After gathering inputs from the public hearing, OED can approve, disapprove, or amend the final EIA plan for the project. There is no deadline for OED to determine the final EIA plan, and they are free to change the area of the project (Lovdata, 2020a). Once there is an **approval of the EIA plan** in the third step**,** the developer is granted the first round of exclusivity to the specific area. This exclusivity means that NVE cannot grant any other developer an approved EIA plan in the same project area.
4. Within a two-year deadline from approval of the EIA plan, a **license application along with the final EIA draft** must be sent to OED. That said, the developer can apply for an extension of up to two years at a time if there is a valid reason to do so. If the developer fails to meet this deadline without an extension, the exclusivity to the area is lost. The final EIA and license application are comprehensive documents providing more detailed information about the energy project, environmental impact, societal effects, estimated annual energy production, grid connection, construction methods, costs, etc (Lovdata, 2020a).
5. In the fifth step, the license application and final EIA draft is sent to another round of **public hearings** (Lovdata, 2020a).
6. Following the public hearing, OED makes a **license decision** in the sixth step based on a comprehensive assessment of the public hearing inputs, application, and previous experiences. If approved, the developer is awarded a license for the proposed OW project presented in the application. The awarded license is valid of up to 30 years from the date the OWF is fully operational. OED can set certain terms and conditions to the awarded license in which the developer must oblige to. These terms are intended to reduce the negative impacts on the environment. At this approval stage,

the developer is granted the second round of exclusivity to the area. If on the other hand the license decision is denied, the developer can **appeal** to the State cabinet who has the final decision in the matter (Lovdata, 2020a).

7. If the license is granted, the developer has another deadline of two years from the awarded license date to send a **final detailed project plan** to NVE. It is worth noting that the developer can again apply for an extension of up to two years at a time if there is a valid reason to do so. If the developer fails to meet the deadline without an extension, the second round of exclusivity to the area is lost. The detailed project plan contains information on the date and duration of construction, technical development description, planned operational phase, financing of energy plant, and plan for removal of the energy plant after the lifetime of 30 years. NVE has the authority to ask for any additional information from the developer regarding the final detailed project plan. NVE then decides on either approving or disapproving the detailed project plan. It is required that NVE approves the construction and operational plans before the construction of the OWF commences. If the final project plan is approved, the developer is granted the third-round in exclusivity to build in the specific area. If the project plan is denied, the developer can once again appeal to OED (Lovdata, 2020a).
8. In the final **build** step, the OWF must be put into operation within three years from the date NVE approved the project plan. The OWF is considered operational once the energy is produced and exported out of the project area. Similar to the other deadlines, extensions of up to two years at a time can be granted for valid reasons (Lovdata, 2020a).

Once the OWF is operational, there will be regular supervisions in order to inspect whether the developer is obliging to the detailed project plan along with the attached terms and conditions. The supervisory authority will consist of relevant representatives from both the Petroleum Safety Authority and NVE (Lovdata, 2020a).

The Ocean Energy Regulation raises some challenges and questions for both the industry actors and OED. For one, there is little room for flexibility. The strict deadlines create logistical and planning concerns for the developers in a time where OW technology is rapidly changing. In addition, there will certainly be competition for the same areas or overlapping areas in the notification step of the license process, which can be seen in table 6 below. According to the regulation, OED can only approve an EIA program to a single developer for a specific area.

This raises the question on what kind of selection criteria OED will base on when choosing between different projects and how long the developer risks awaiting the decision. Ann Myhrer Østenby at NVE mentioned it was probable that OED would choose selection criteria based on a developer's financials, past offshore experience, track record in Health and Safety, and probability of success for the intended project (conversation 30th June 2020). In a press release by OED (2020b), Ministry of OED Tina Bru responded to this selection criteria uncertainty by announcing that there will come a guide to the license process by spring 2021. The guide will be released a few months after the opening of the license process in January 2021, and therefore creates uncertainty for early applicants. In addition to the guide and adding to the uncertainty, OED will assess the need for any changes to the Ocean Energy Regulation (OED, 2020b). Therefore, it is yet to be fully determined how the license process will unfold.

Table 6 Overview over competitors for the OW areas. Companies with a high probability participation in the license process have publicly announced their intention to apply. The rest are rumoured interests. Amount of competition raises questions regarding selection criteria. Authors own

Company	**Consortium partner**	**Participation probability**	**Area and capacity**
Aker Offshore Wind	Aker BP	High	Utsira Nord : 500MW Sørlige Nordsjø II: 1500MW
Equinor	Not available (n.a)	High	Expressed interest in both areas.
Fred Olsen Renewables	Hafslund Eco	High	Expressed interest in both areas. "Industrial size project."
Hitech	Eni	High	Expressed interest in both areas
Norgesgruppen	Norseman	High	Sørlige Nordsjø II: 1500MW
Shell	n.a	High	Rumoured interest in Utsira Nord
Iberdrola	n.a	Medium	Rumoured interest in both areas
Magnora	n.a	Medium	Rumoured interest
Cloudberry Clean Energy	n.a	Medium	Rumoured interest.

3.3 The Energy law: Onshore transmission infrastructure

For energy projects requiring an EIA after the Energy Law, §6 in the Ocean Energy Regulation opens the possibility for a joint EIA assessment (Lovdata, 2020a). Electrical installations and transmission lines can only be built, owned and operated in accordance with a license under the Energy Law §3-1. As specified in §1-1, the law is applicable in areas up to the Norwegian baseline (Lovdata, 1990). In order to transmit the produced electricity from an OWF to onshore grid facilities, there must be electrical installations crossing the territorial baseline. From this interpretation, an OWF requires two licenses to transmit the electricity to onshore facilities. The first license is required under the Ocean Energy Regulation to transmit the electricity from the OWF up to the baseline. From there, a second license is required under the Energy Law to transfer the electricity from the baseline to the onshore facilities.

Figure 45 Territorial extent of the Ocean Energy Law versus Energy Law. Authors own

That said, §1-2 of the Ocean Energy Law does include the possibility for the State to expand the geographical reach of the license through a supplemental regulation. For an example, the State can through a regulation include the area between the territorial baseline and shoreline. Accordingly, the license obtained through the Ocean Energy Law could be valid for sea cables crossing through the territorial baseline and all the way up to shoreline (Lovdata, 2010).

Anyway, there is certainly a requirement to obtain a license from the Energy Law when connecting to onshore grid facilities. Without going into details, the license process covering the Energy Law follows roughly the same step procedures as described for the Ocean Energy Regulation.

3.4 Other relevant laws

Other relevant laws that need to be considered when developing an OWF are listed in the summarized table 6. This includes the Biodiversity law, Ports and Waterways law, Pollution Control Law, and Cultural Heritage law.

Table 7 Summary of central laws for developing an OWF. Source: Authors own

Law	**Within territorial baseline**	**Outside baseline**
Energy Law *(Energiloven)*		
Biodiversity law *(Naturmangfoldloven)*		
Ports and waterways law *(Havne- og farvannsloven)*		
Ocean Energy Law *(Havenergilova)*		
Pollution Control law *(Foruresningsloven)*		
Cultural Heritage Law *(Kulturminneloven)*		

The purpose of the Biodiversity law is to protect all nature on land and at sea in a sustainable manner. According to §2, the law only applies within the Norwegian territorial baseline. That said, the law outlines several environmental principles which shall be considered by the public authorities in any decision-making process relating to interventions within the economic zone of Norway. Consequently, the environmental principles are required to be considered by the licensing authorities when deciding on an OWF project outside the baseline (Lovdata, 2009).

According to §2, The Pollution Control law serves to protect the environment against pollution and reduce existing pollution. The law applies to the economic zone of Norway and will therefore come into effect outside the baseline. The definition of pollution has a wider meaning beyond the traditional sense according to §6 of the law, which amongst other definitions can include noises, tremors, or adding foreign substances in the water/air (Lovdata, 1981). This could be relevant in the installation, operational, or decommissioning phase for an OWF in which the developer will be required to apply for a permit to pollute.

The Cultural Heritage law states in §1 the aim to protect Norwegian archaeological, architectural, and cultural sites in the overall environment and resource management. As stated in §9, a developer is required to investigate whether the planned project will affect a cultural monument or sites. If a developer plans to build an OWF in such a site, it is required to apply to the authority for an exemption to build. If this is denied, the developer needs to find an alternate location (Lovdata, 1978).

Last, the purpose of the Ports and Waterways law is to facilitate an efficient, safe, and environmentally friendly maritime operation in ports and the use of ocean waters, both within and outside the baseline. According to §14, a developer is required to apply for a building permit for a planned energy project along with the electrical sub-system (Lovdata, 2019). For an OWF, this includes necessary permits for the turbines, transformation station, and sea cables.

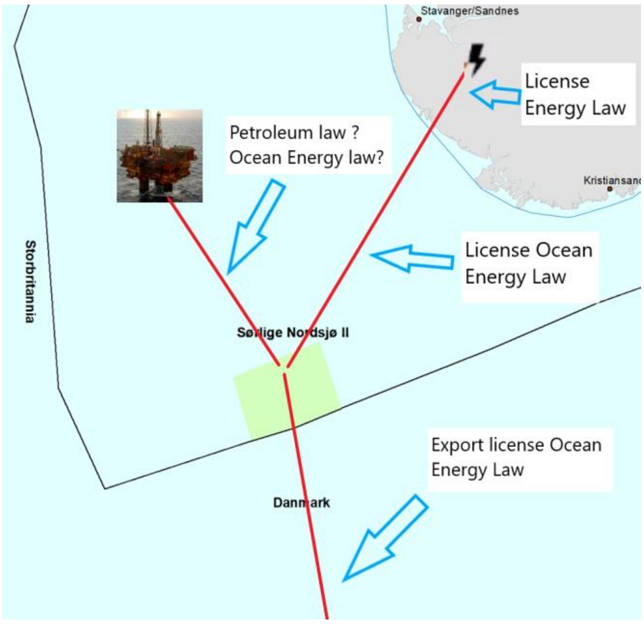


Figure 46 Overview over which law applies to transmission lines. Red are example transmission cables. Authors own

4.1 Case study

4.1.1 Background to case

Developing offshore wind in Norway can contribute to industrial development, reduced CO2 emissions, and increased Norwegian production of renewable electricity. Generations of mastering extreme ocean conditions has given Norwegian suppliers a unique engineering and marine competence. Decades of Norwegian oil and gas experience and competence in deep waters can be transformed to the OW industry. This includes competence in areas within project management, development, operations and maintenance. As a response to the massive global market potential, the Norwegian government opened the ocean areas “Sørlige Nordsjø II” and “Utsira Nord” for the development of a domestic OW market. Both areas were included in a shortlist of 15 areas recommended by NVE in their 2012 report *Offshore Wind Power in Norway: Strategic Environmental Assessment* (Berg et al., 2012)

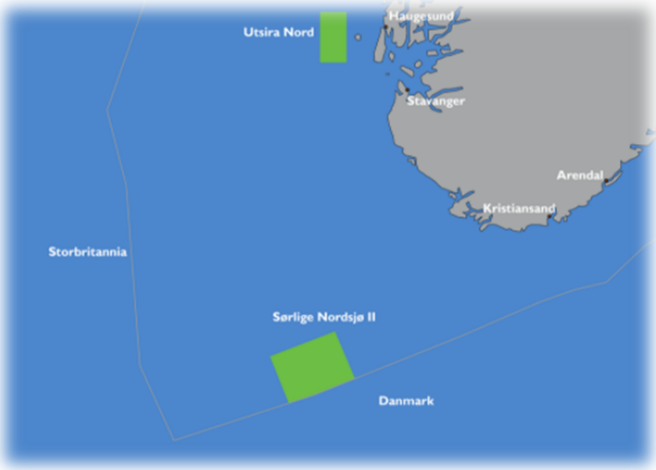


Figure 47 Map illustrating the green areas open to apply for a license. Source: (Olje-og-Energidepartementet, 2020)

Table 8 provides a descriptive overview of each area. Both areas were selected based on their strong wind resources, technical feasibility in terms of grid connection, and relatively low impact on the environment. The areas differ in terms of technology and max potential capacity. With average water depths between 50-70m, Sørlige Nordsjø II is more suitable for deep water bottom-fixed projects (Berg et al., 2012). That said, certain floating wind technologies with low drafts is also a possibility within this area. In contrast, Utsira Nord is solely suitable for floating wind technologies considering the area has average water depths between 220-280m (Berg et al., 2012). Given that bottom-fixed technologies are comparatively more mature than floating technologies, Sørlige Nordsjø has twice the allowed max potential capacity than Utsira Nord. The proximity to the Ekofisk oil field and the European continental grid connection opens potential power offtakes for developers in Sørlige Nordsjø II. Utsira Nord appears to be a domestic playground for floating wind technologies that can eventually be exported to international markets.

From a developer's point of view, the area of choice for the case study fell on Sørlige Nordsjø II. The pre-selection criteria for the area were based on the wind resource, water depth, grid connection, potential conflicts, technology maturity, and cost. According to Ann Myhrer Østenby at NVE, it is more likely that OWF will be built out at Sørlige Nordsjø II before Utsira Nord due to the technology maturity of bottom-fixed turbines compared to floating turbines (conversation on 30th June 2020). Therefore, the initial solution for this thesis concludes it would be more feasible to develop an OWF in Sørlige Nordsjø II than Utsira Nord, hence the reason for choosing this area.

Table 8 Utsira Nord and Sørlige Nordsjø II. Source: Berg, K., et al. (2012, Desember). "Havvind - Strategisk Konsekvensutredning." Norges vassdrag og- energidirektorat. from http://publikasjoner.nve.no/rapport/2012/rapport2012_47.pdf.

Description	Sørlige Nordsjø II	Utsira Nord
Area	2591 km²	1010 km²
Average depths	50-70m	220-280m
Average wind speed	10.5 m/s	10.2 m/s
Distance to shore	140 km	22 km
Offshore Wind Technology	Mainly bottom-fixed	Floating
Max Capacity	3GW	1.5GW
Comments	Potential connection to European continental grid High petroleum activity (Ekofisk + Tor)	More suitable for floating demonstration projects.

4.1.2 Description of area

4.1.2.1 Wind farm location

The proposed wind farm will be in the Sørlige Nordsjø II area. As seen in the figure below, Sørlige Nordsjø II covers an area of 2591 km^2 within the yellow lines.

Figure 48 Sørlige Nordsjø covers an area 2591 km^{2}of within yellow lines. Authors own through Google Earth

Zooming into the same location, the location of the proposed wind farm can be seen in the red rectangle within grid points A, B, C, and D. The red area covers approximately 44 km^2. The UTM coordinates are given in the table.

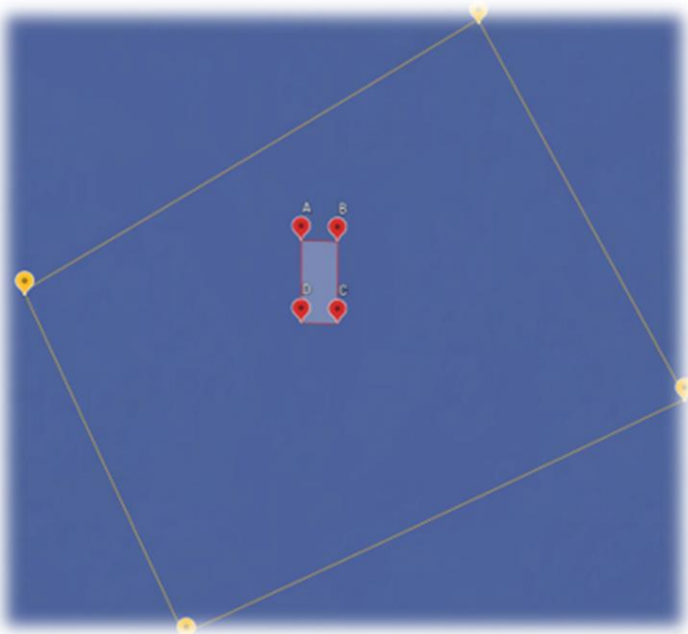


Figure 49 Red rectangle illustrates the planned OWF in Sørlige Nordsjø II. Authors own through Google Earth

Table 9 UTM Coordinates of planned OWF. Authors own

Corner grid	North UTM	East UTM
A	6311577	246860
B	6311227	250838
C	6302248	250300
D	6302579	246312

4.1.2.2 Wind conditions

Good wind conditions are crucial for the economic feasibility of an OWF project. According to Berg et al. (2012), the Sørlige Nordsjø II area is estimated to have very good wind conditions with an average wind speeds of 10,5 m/s. Average wind speeds above 8.5 m/s are classified as very good. The wind resource for NVE's report was simulated by Kjeller Vindteknikk using the meso-scale model Weather Research and Forecasting between the years 2005-2006 (NVE, 2009). The result showed excellent wind conditions within the Norwegian Economic zone.

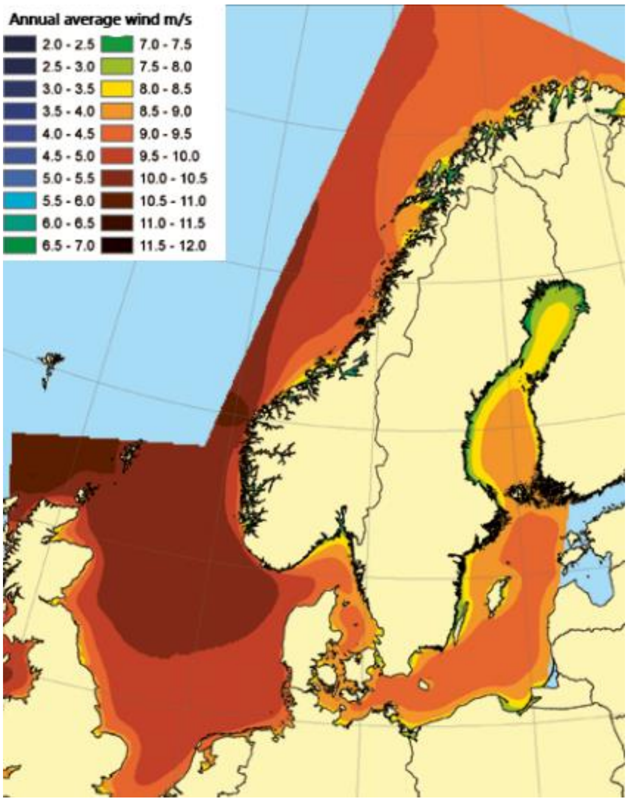


Figure 50 Annual average wind speed in 100m height. Source: NVE (2010). "Havvind: Forslag til utredningsområder." Retrieved 20/11, 2020, from https://publikasjoner.nve.no/diverse/2010/havvind2010.pdf.

Attempt was made to retrieve the raw data from Kjeller Vindteknikk for the specific area of interest for this thesis, however due to current commercial interests in the data this attempt was unsuccessful. That said, Stormgeo was able to provide excellent wind data free of cost for the project area. The Stormgeo wind data is a 0.25-degree resolution, ERA5 hourly time-series simulated up to 100m heights for the project region between the years 1999-2019. In addition, the data includes the wind direction, temperature, extreme wind gusts, and total precipitation.

The time-series wind data covering the year of 2019 is shown in figure 48 below. This is to show the variability of the wind during the seasons in the area. The measured wind is stronger on average during the winter and fall compared to the summer season. The average wind speed for the entire measurement period between 1999-2019 is calculated at 10.2 m/s which is illustrated by the black line in figure 51. Compared to the Kjeller Vindteknikk data, the calculated average wind speed from Stormgeo is moderately lower.

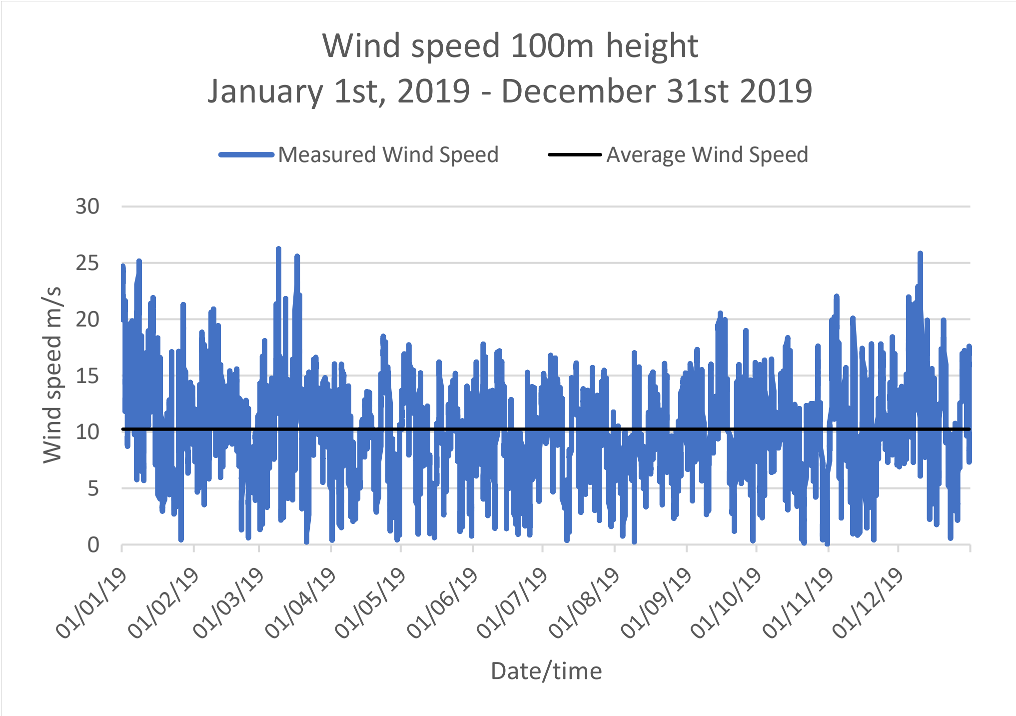


Figure 51 Time-series wind data for the region in year 2019. Authors own, data provided by Stormgeo.

For the entire wind data set between 1999-2019, the histogram below summarizes the distribution of the measured wind speeds. This provides a graphical representation of the strong wind resource in the area.

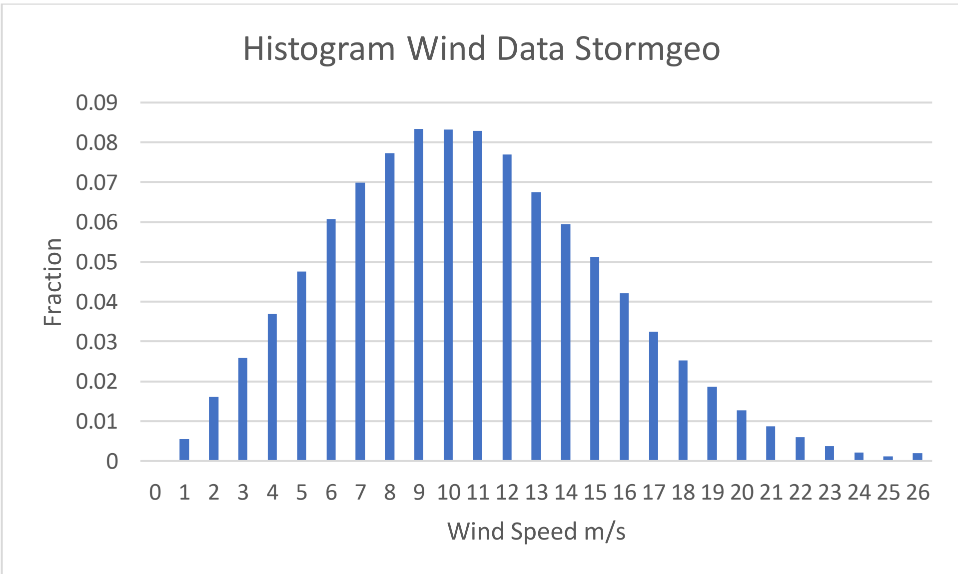


Figure 52 Distribution of measured Stormgeo wind speeds years 1999-2019. Authors own, data provided by Stormgeo.

The wind rose in figure 53 illustrates that the wind in the area predominantly comes from the South West, West, and North West direction.

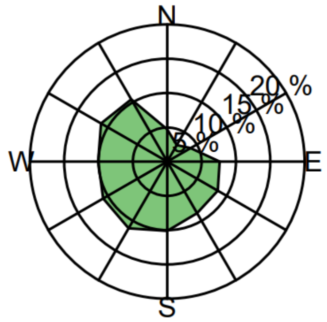


Figure 53 Wind rose for the planned OWF area. Source: Stormgeo (2012). "Kraftproduksjon og vindforhold– fagrapport til strategisk konsekvensutredning av fornybar energiproduksjon til havs." Retrieved 8/12, 2020, from https://evalueringsportalen.no/.

4.1.2.3 Ocean Depth

According to (Berg et al., 2012), the average depth of the ocean in Sørlige Nordsjø II varies between 50-70m. Ocean depths for specific areas within Sørlige Nordsjø II is difficult obtain as this area simply has not been explored in detail. Kartverket, the mapping authority in Norway, lacks detailed modern depth data for the Sørlige Nordsjø II area. However, Arnstein Osvik, senior engineer at Kartverket Ocean division, has provided the author with a low-resolution map over Sørlige Nordsjø II which is used for nautical products and services (Wang, 2020a). The map is shown below in figure 54 where each point gives the ocean depth level.

For the case study area, it is appropriate to take an average of the nearest depth points. The nearest depth points are 64m, 60m, and 62m, giving an average ocean depth of 62m for the project area.

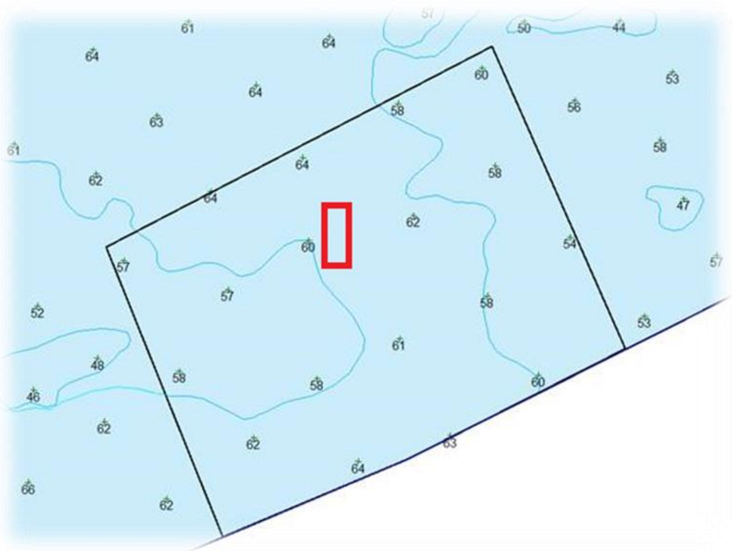


Figure 54 Low resolution depth data of Sørlige Nordsjø II with location of OWF in red. Source: Wang, A. (2020). Dybde kart av havbunn Sørlige Nordsjø II / Utsira Nord (email to Arnstein Osvik 19/10/2020)

4.1.2.4 Ocean bed characteristics

According to the (Mareano, 2020) mapping services provided by NGU, the project encompasses an ocean bed area made up of sandy sediments.

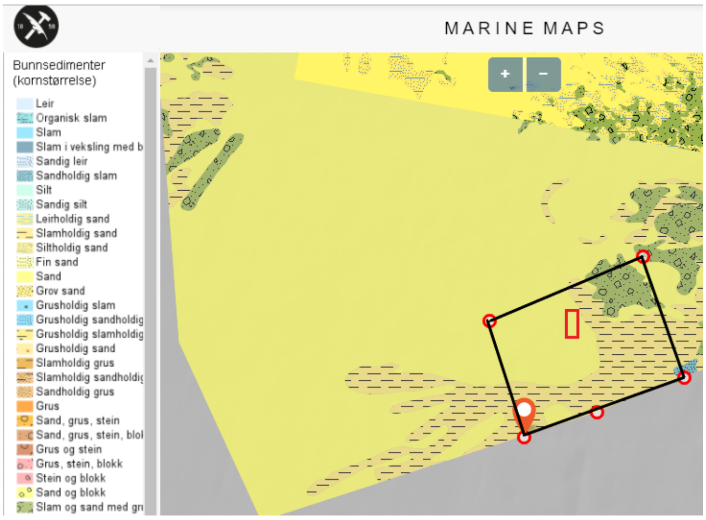


Figure 55 Ocean bed sediment characteristic map provided by NGU through their Mareano program. Authors own screenshot Source: Mareano (2020). "Mareano: Samler kunnskap om havet." Retrieved 20/11, 2020, from http://mareano.no/kart/mareano.html#maps/4789.

However, the drawback of the Mareano marine map is that it only covers the top layer of the ocean bed. As OW foundations typically are drilled down to depths of up to 30m, it is necessary to investigate the geotechnical sediments in these depths. This sort of information does not exist for the specific project area. That said, Svein Finnestad at the Norwegian Petroleum Directorate provided a geotechnical assessment report produced by oil major Repsol when the company was exploring for new oil fields back in 2012 (Wang, 2020b). Although the geotechnical assessment site is approximately 50 km from the project area, it should give a rough representation of the depth layers due to the similarities of the seabed.

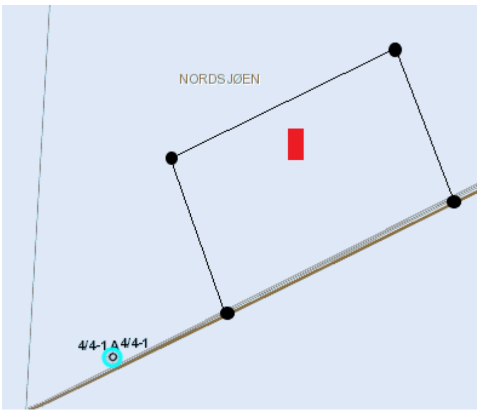


Figure 56 Site of the geotechnical assessment report produced by Repsol highlighted in blue circle. This is approximately 50 km from the project area in red. Source: Oljedirektoratet (2020). "Faktasider." Retrieved 20/11, 2020, from https://factpages.npd.no/no/wellbore/pageview/exploration/all/7273.

From the report, geotechnical bore holes from the site shows that core sections are made up of both sand and clay in depths of up to 50m (Repsol, 2012). Therefore, the master thesis will assume this is the case for the project area as well.

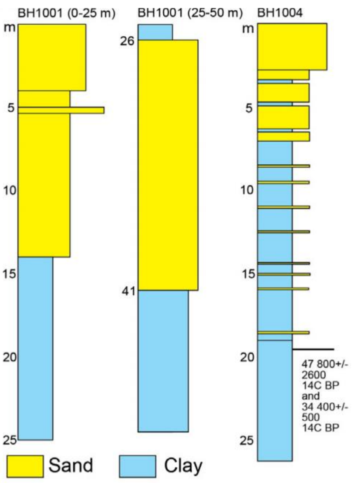


Figure 57 Geotechnical core sections from the boreholes assessed by Repsol. Source: Repsol (2012). "GEOPHYSICAL SITE SURVEY NCS BLOCK 4/4 : Operations report."

Table 10 provides a summary of the technical characteristics of the area. Icing and wave data was provided by Stormgeo (2012). Icing can cause power production losses as it degrades the aerodynamic performance of a turbine (Norwea, 2018). According to the data, icing is not an issue for the area. The wave data highlights significant waves in the area which poses a challenge to the structural design of the foundation.

Table 10 Summary technical area characteristics.

Area characteristics	
Area of project	44 km^2
Distance to nearest Norwegian shoreline	170 km
Average wind speed	10.2 m/s
Wind direction	Mainly from South-west, North-west
Average ocean depth	62 m
Ocean bed characteristic	Sand and clay in depths up to 50m
Icing	Not significant, moderate icing 0% of time
Significant 50 years wave height	12.9 m
Percent of time with significant wave under 2,5m	70.9%
Percent of time significant wave height under 1.5m	44.9%

4.1.3 Technical

4.1.3.1 Turbine choice

The offshore turbine of choice for the project case is the Siemens Gamesa SG 11-193 DD Flex. Launched in 2019, the 11 MW turbine will be commercially installed in Vattenfall's "Hollandse Kust Zuid 1-4" offshore wind farms in the Netherlands in 2022 (Durakovic, 2020). This is the largest rated turbine available in the software program WindPRO and therefore the choice for the project. The desire for the project is to maximize the annual energy production, therefore it is natural to choose the turbine that has the largest rated capacity while simultaneously commercially available. Additional technical details of the turbine are summarized in table 11.

Figure 58 Illustration of the Siemens Gamesa SG 11-193 DD Flex turbine. Turbine has swept area of 29,300 $m^2$and rotor diameter of 193 meters. Source: Siemens Gamesa (2019). "The new SG 10.0-193 DD." Retrieved 20/11, 2020, from https://www.siemensgamesa.com/-/media/siemensgamesa/downloads/en/products-and-services/offshore/brochures/siemens-gamesa-offshore-wind-turbine-sg-10-0-193-dd-en-double.pdf.¨

Table 11 Table showing the technical features of the turbine. Source: Wind Turbine Models (2019). "Siemens Gamesa SG 11.0-193 DD." Retrieved 20/11, 2020, from https://en.wind-turbine-models.com/turbines/2125-siemens-gamesa-sg-11.0-193-dd

SG 11-193 DD Flex technical features	
Manufacturer	Siemens Gamesa
Nominal power	11 MW / 11,000 kW
Rotor Diameter	193m
Swept area	29,300 m^2
Hub height	Site specific
Number of blades	3
Length of blades	94 m
Gear box	Direct drive
Power density	375.4 W/m^2
Tower type	Steel cylindrical tube
Product launch date	November 2019
Commercial debut	Vattenfall's Hollandse Kust Zuid 1-4 wind farms expected operational in 2023.

4.1.3.2 Foundation type

According to Cedric Vanden Haute, design lead at Parkwind, the optimal foundation choice for the project area is a 4-legged steel jacket bottom-fixed foundation (conversation 12th November 2020). The 4-legged jacket foundation was also recommended by Huw Traylor, principal engineer at DNV (conversation on 11th December 2020). Therefore, a 4-legged jacket foundation will provide support for the turbines located in the area's harsh marine environment with significant waves. The water depth is too deep for other bottom-fixed structures such as the commonly used monopile. It is also logistically easier to assemble and install a 4-legged jacket foundation. According to table 4 presented earlier, the sand and clay seabed characteristic of the project area is ideal for the jacket foundation suction buckets that are sucked into the seabed. It is also important to note that floating foundation could be a technically viable option in the future for the site, however as discussed in chapter two, these structures will be too costly for the project area and too risky due to the technological immaturity. Inquiring about the possibilities of floating foundations, Magnus Ebbesen, Business Lead Floating Wind at DNV, responded that the water is too shallow in the area for current floating technologies (conversation on 11th December 2020). Further, according to Morten Magnussen, project manager at Norsea Group, current floating structures lack port infrastructure for serial assembly for this project due to the water depth needed at port (conversation on 13th November 2020). If this project were to be built from 2030 or onwards, it is important to note that floating structures could be an option. However, this project case is assumed to be in operation at an earlier date and therefore it is a better technical option to choose the established 4-legged jacket foundation for the proposed OWF project case.

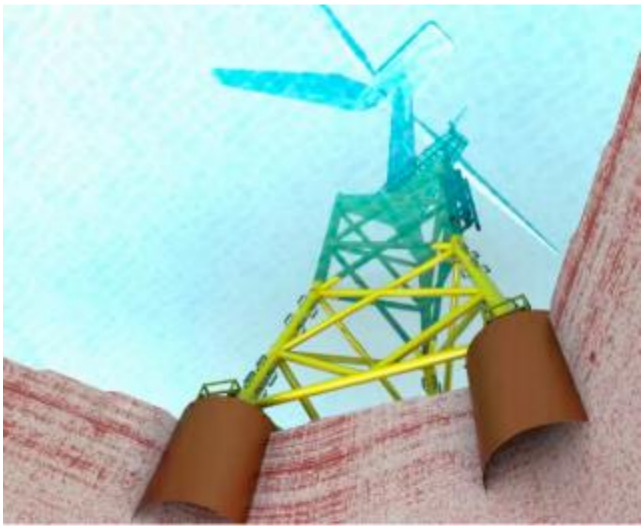


*Figure 59 Example of the jacket foundation sucked into the seabed using suction buckets. Source: Skau, K. S., et al. (2019). "Modelling of soil-structure-interaction for flexible caissons for offshore wind turbines." Ocean Engineering **171**: 273-285*

4.1.3.3 Wind farm layout

This section will explain the layout of the OWF case which will be used as an input to the software WindPRO. The technical design of the OWF layout is an important component in minimizing the losses, which in turn will help maximize the economic returns. As previously mentioned, the turbines should be located as tighly as possible to each other in order to reduce the cabling cost. However, the layout also needs to consider the wake effect losses that incur between the turbines.

According to DNV (2018) and Norwea (2018), a minimum spacing of 6 rotor diameters in the prevailing wind direction and 4 rotor diameters in the non-prevailing direction is recommended for the layout spacing. Applying this general rule to the case, there will be a turbine spacing of 1158m (6*193m rotor diameter) in the prevailing wind direction and 772m (4*193m rotor diameter) in the non-prevailing wind direction. Installing 50 turbines will therefore require an area of approximately 44 km^2.

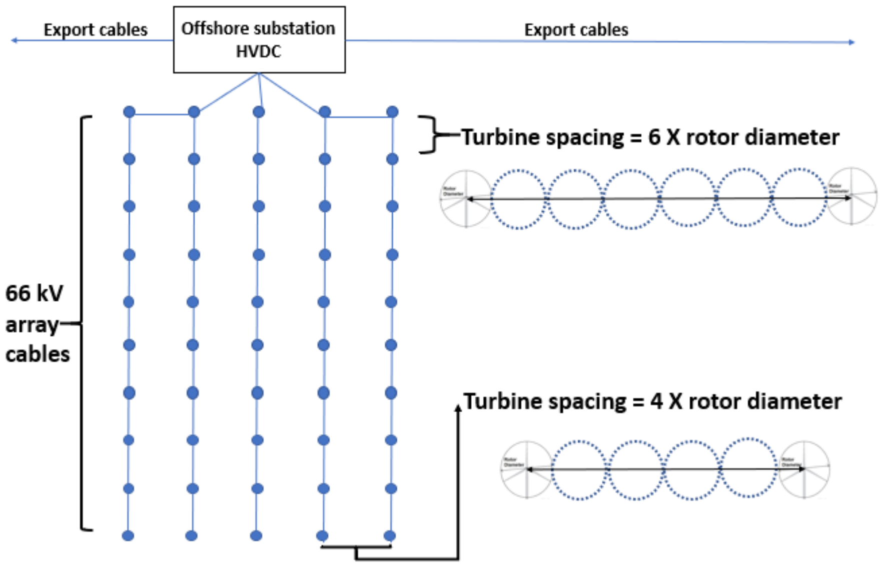


Figure 60 Layout of OWF project case. Blue dots represent turbines. Authors own

The OWF will also be installed with 66kv inter-array cables that connect the turbines to each other and finally all aggregate to the common HVDC offshore substation. By using a higher 66kv rather than the standard 33kv, less array cabling will be required and therefore reducing costs (DNV, 2015). From the offshore substation, direct current export cables will bring the power to their connected destinations.

4.1.3.4 Power connections

An important aspect for the OWF is to have technical solutions for grid connectivity. This is especially a challenge for OW developers in the Norwegian market. OW projects in Norway will likely face little support in terms of subsidies and will therefore rely on profitable power prices, something they will not necessarily find in the Norwegian low-priced power market. There will also be a challenge for the domestic Norwegian grid to handle a rapid increase in power imports. Therefore, to build profitable projects, a developer must consider all the connectivity solutions which can help maximize economic returns (Sandbekk, 2020).

Examining figure 61, there are several potential power connections points in the near proximity to Sørlige Nordsjø II. For one, the power can be transmitted onshore to the domestic grid market or to hydrogen production facilities. Second, the high petroleum activity to the west opens the possibility for electrifying several oil platforms with OW power. Further, Norway is currently in the process of expanding their power export capabilities. Aside from the current export undersea cables to Denmark (1) and Netherlands (3), two additional export links to the United Kingdom and Germany are expected to be completed soon. This includes the 1400 MW Nordlink cable (2) to Germany and the 1400 MW North Sea Link cable (4) to the United Kingdom (Statnett, 2020). Finally, the European Commission (2020) includes hybrid energy island hubs in the North Sea as part of their 2020 offshore renewable energy strategy. If hybrid offshore energy islands become a reality, it could serve as a future tie-in point for OWF in Sørlige Nordsjø II, enabling cost efficient grid connection between multiple member countries. As part of the North Seas Energy Cooperation, Norway certainly supports such a future grid development in the North Sea. Thus, there are several potential connection points from Sørlige Nordsjø II.

Figure 61 Possible power connection points. Source: Sandberg, J. (2020). "Aker Offshore Wind." Retrieved 24/11, 2020, from https://www.statnett.no/contentassets/94e165aba0e94c9eb0b6eeacbd017028/hva-trengs-for-a-fa-til-en-storstilt-utbygging-av-vindkraft-til-havs---aker-offshore-wind.pdf.

For the OWF project case, there are several potential connection points that can provide flexibility for the produced electricity. The power can then be sold to the connection point with the highest price, thereby maximizing economic returns. The OWF could also enable power offtake agreements with certain companies, such as onshore factories, which would bring a reliable revenue stream to the project. Figure 62 illustrates the potential connection points for the OWF project case.

Figure 62 Potential connection points for the OWF project case. Authors own

The first potential connection point (1) could be to the Conoco Phillips owned Ekofisk oil field. Part of the electricity produced by the OWF would be used electrify the oil installation which is currently electrified by gas turbines. According to Frode Oplenskedal, Project Manager Electrification at Conoco Phillips, the Ekofisk electricity demand stands at 200MW (conversation on 18th November 2020). According to him, the electrification project is an ongoing engineering project at the company which includes the option of tying in OW power. Whether Conoco Phillips decides to pursue the electrification via OW depends on the cost of replacing the gas turbines. The company aims to conclude within a year if the electrification project is economically feasible. Thus, it is an uncertain possibility for the OWF case to electrify the Ekofisk oil field.

The second connection point (2) is to transmit the power to onshore grid facility in Norway. This would allow the power to be sold into the domestic Norwegian power market. At the same time, the power could be used to produce hydrogen via electrolysis on onshore facilities at times of low prices. Another possibility is to connect to a pumped hydro-power plant on the west coast of Norway. According to Grete Høiland, Executive Vise President of Infrastructure at Lyse, the company is currently investigating pumped-hydro possibilities for their hydro power plants in the southwest of Norway and are looking into the feasibility of using electricity produced from OW (conversation on 18th November, 2020).

The third connection point (3) is to tie into the Nordlink export cable which is expected to be completed within 2025. This would enable the OW power to be sold into the German power market.

The fourth last connection point (4) is to connect the OWF with a potential energy hub artificial island that the European Commission aims to develop.

The last potential connection point (5) is to connect into the North Sea Link cable, allowing the electricity produced to be sold into the U.K power market.

4.1.3.5 Power production simulation: WindPRO

The wind data along with the defined technical parameters for the project area enables the author to calculate the AEP. As mentioned in the methods section, the software WinPRO version 3.4 was used by the author to estimate the AEP for this specific project. The wind data provided by Stormgeo was used as data input to the software.

The software also allows the user to set required parameters. Jensen's wake model, which was described in figure 16, was set as the default wake model. The wake decay constant, which defines the rate of expansion of the wake and the recovery rate of the wind speed, was set at the default "offshore" level 0.050 in the program.

Climatic data from the nearest climate station was then determined. The nearest climatic data station in the software database was Lista Fyr, located approximately 170 km from the project area. Although far away from the project area, the data should provide a decent approximation. The climatic data includes base temperature, base pressure, air density, and relative humidity.

Next, the technical features along with the layout of the farm was determined in the software. The technical features include the predetermined choice and number of the Siemens Gamesa SG-11 193 DD turbines along with its hub height of 120 meters. The turbine layout of in the OWF was placed according to the correct coordinates along with the distances between the turbines.

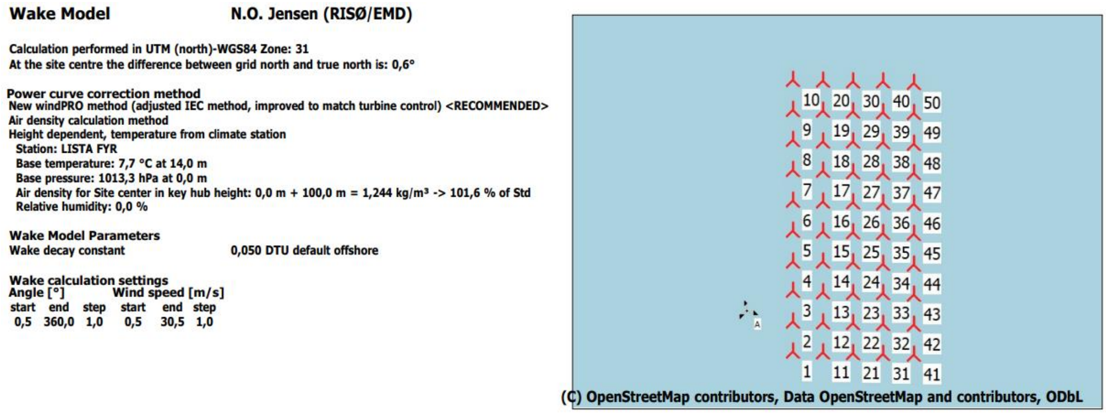


Figure 63 Parameters and layout of the project OWF in WindPRO. Authors own via WindPRO

After all the necessary parameters are set, the software can begin calculating the gross annual energy production. The full resulting document is presented in the appendix. However, table 12 summarizes the main results.

Table 12 Summary of WindPRO results. Source: Authors own

WindPRO calculation results for project area	
Total Rated Power (MW)	550
Average wind speed at hub height (m/s)	10.4
Full load hours (hours/year)	4601
Capacity factor (%)	52.5
Total wake loss (%)	9.4
Other losses (%)	10
Annual Energy Production results:	
Gross Annual Energy Production (no losses) (GWh/year)	3102.21
Annual Energy Production (with wake loss) (GWh/year)	2811.88
Net Annual Energy Production (with all losses) (GWh/year)	2530.7

After accounting for both total wake losses and other losses, the WindPRO results show that the OWF produces a net AEP of 2530.7 GWh. Other losses account for occurrences such as turbine malfunctions, grid unavailability, maintenance, and other factors that could interfere with the production.

Overall, the results are strong. Average net energy generated per turbine stands at 50.6 GWh per year. The capacity factor of 52.5% is above IEA (2019b) estimations of 40-50% in new OW projects. Moreover, the total wake loss of 9.4% is an acceptable level for the OWF.

4.1.2 Economic assessment

After investigating the regulatory requirements, technical feasibility, and estimated power production from WindPRO, this thesis can now determine the economic feasibility of the OWF case. The result of the economic assessment will provide the investor with a more informed decision on whether to invest or not.

This section will first introduce the assumptions for the cash flow calculations performed in Excel. From there, the economic feasibility results for the following three scenarios will be presented:

- **Scenario 1:** Connecting, transmitting and selling all the electricity produced to the Norwegian power market
- **Scenario 2:** Connecting, transmitting and selling all the electricity to the United Kingdom power market.
- **Scenario 3:** Connecting, transmitting and selling the electricity to the German power market.

4.1.2.1 Assumptions

It is assumed that the OWF has secured a license and will commence construction in the year 2024. The construction period is assumed to take two years until the OWF is fully operational in the year 2026. It is also assumed no bottlenecks in each of the countries domestic power transmission lines. Further assumptions for the project case are summarized in table 13 and these will be discussed stepwise below.

Table 13 OWF project case assumptions. Authors own

Project case assumptions	
CAPEX cost per MW installed (NOK/MW)	25,149,273
OPEX cost per MW installed (NOK/MW/year)	570,000
Average electricity price Norway (NOK/MWh)	380
Average electricity price Germany (NOK/MWh)	447.5
Average electricity price U.K (NOK/MWh)	502
Lifetime project (years)	30
Real discount rate (%)	6
Nominal discount rate (%)	8.12
Nominal discount rate after tax (%)	6.33
Inflation (%)	2.0
Tax (%)	22.0
Depreciation rule	Linear over 5 years
Debt-equity ratio (% / %)	70% / 30%
Loan interest rate (%)	3.5
Loan type	30-year serial loan
Policy support tools (financial incentives)	none

4.1.2.1.1 CAPEX cost per MW installed

Based on NVE (2019a) own estimates in their report *Cost in the Energy Sector*, CAPEX cost per MW installed for OW stands at 27,792 NOK/kW , which translates into approximately 27,8 MNOK/MW installed. This number is not too far off from the 28,1 MNOK/MW average CAPEX per MW from calculated from various projects in table 4. However, NVE highlights a large uncertainty in their estimates due to the variations in OW projects. In addition, their cost estimates were undertaken in the year of 2019 which can result in slightly outdated cost models.

In order to lower this uncertainty, the author contacted the Belgian OW developer Parkwind for updated cost information. Parkwind is currently operating four OWFs with total operating capacity of 771MW and are planning on developing two further. Ann Berckmans, Business Development Analyst at Parkwind, provided approximate CAPEX cost per MW for their future OW projects currently in pre-development phase (conversation on 12th November 2020). Converted from Euro to NOK, the CAPEX cost per MW for these projects amounted to 22,506,545 NOK/MW, or approx. 22,5 MNOK/MW. This CAPEX cost from an active OW developer should serve as a good proxy for future anticipated cost reductions within OW.

To capture future anticipated cost reductions whilst also accounting for uncertainty, CAPEX cost per MW for this thesis will be based on an average between NVE current estimates and Parkwind expected estimates. This amount to: $\frac{22{,}506{,}545+27{,}792{,}000}{2}$= 25,149,273 NOK/MW. This cost excludes grid connection costs as it is assumed that the national transmission system operator (TSO) in each country incurs these costs and is responsible for the offshore connection development. This is assumed as this current case for other European countries such as Germany, Netherlands, Denmark, Belgium, and France (Navigant, 2019).

4.1.2.1.2 OPEX cost per MW installed

OPEX cost per MW installed assumed for this thesis is also gathered from NVE (2019a) *Cost in the Energy Sector.* This amounts to 570 NOK/kW/year, or 570,000 NOK/MW/year.

4.1.2.1.3 Average electricity price

The average electricity prices used to determine the income of the OW project will be based on future prognosis for Norway, Germany, and United Kingdom.

According to NVE's analysis, expected average electricity prices in Norway between the years 2020-2040 will lie in the range between 38 and 42 øre/kWh in real 2020 values (NVE, 2020). To act prudently, the lower bound Norwegian average electricity price of 38 øre/kWh will be assumed for the project lifetime. This is calculated to 380 NOK/MWh.

In the same NVE analysis, average electricity prices in the German power market between the years 2020-2040 is expected to lie at 44.75 øre/kWh (NVE, 2020). This is calculated to 447.5 NOK/MWh which will be the assumed average electricity price sold into the German power market. In similar fashion, the U.K expected average electricity prices for the U.K power market is calculated 502 NOK/MWh.

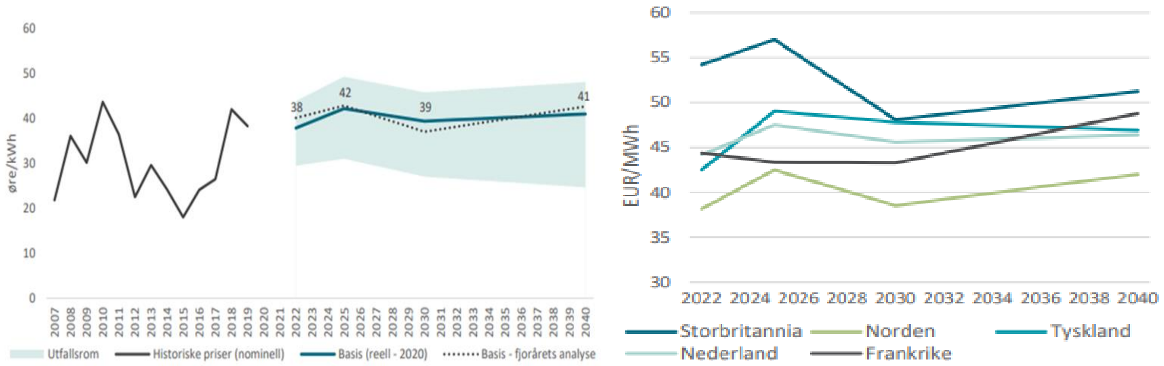


Figure 64 Expected electricity prices Norwegian market (left) and German electricity prices (right). Source: NVE (2020). "Langsiktig kraftmarkedsanalyse 2020-2040 ". Retrieved 22/11, 2020, from http://publikasjoner.nve.no/rapport/2020/rapport2020_37.pdf.

4.1.2.1.4 Lifetime of project

The economic lifetime of the project is assumed to be 30 years based on the recent cost estimation by NVE (Østenby, 2019). The awarded licenses for OW development in Norway will last for 30 years, hence cementing future lifetime expectancies. However, it can be argued for lifetimes of 30-35 years as OW technology has improved in the past few years. As earlier mentioned, this claim has been backed by Stephen Bull at Equinor who claims to be able to increase Equinor's lifetime projects of up to 35 years or even as high as 50 years (Bull, 2020). That said, a prudent approach for this assessment is to set the lifetime at 30 years.

4.1.2.1.5 Real discount rate, nominal discount rate, inflation

NVE recommends a real discount rate of 6% and is therefore assumed for this assessment (Østenby, 2019). Inflation rate is set at 2% based on Norway's monetary policy target (Norges Bank, 2020). The nominal discount rate p is therefore calculated as follows:

$$p_{nominal} = p_{real} * \left(1 + i_{inflation}\right) + i_{inflation} = 6\% * (1 + 2\%) + 2\% = 8.12\%$$

For discounting cash flow to equity after taxes and deduction, it is necessary to apply the nominal after-tax discount rate. This is calculated as follows:

$$p_{nominal\ after\ tax} = (p_{nominal}) * \left(1 - s_{tax\ rate\ (\%)}\right) = (8.12\%) * (1 - 22\%) = 6.33\%$$

4.1.2.1.6 Tax and tax depreciation rule

The tax rate is set at 22% according to the Norwegian tax laws (Regjeringen, 2020).

Any tax depreciation rules are yet to be determined for OWF in Norway, therefore it is assumed that the same depreciation rules found for onshore wind projects will be applied to OW. According to the Norwegian tax law §14-51, onshore wind fixed assets can be linearly depreciated over 5 years (Lovdata, 2020b). This was implemented as an incentive for onshore wind development. It is reasonable to assume a similar incentive for OW in Norway. A linear depreciation rule over 5 years for all the fixed OW assets will therefore be applied to the calculation.

4.1.2.1.7 Debt to equity ratio and Loan

According to Mathias Van Steenwinkel, Business Development Manager at Parkwind, the company typically operates with a debt share of 70% and equity share of 30% for financing their projects (conversation on 12th November 2020). This debt and equity share to finance the CAPEX cost will therefore be assumed for this assessment.

The debt for the project will be financed through a 30-year serial loan with a nominal interest rate of 3.5%.

4.1.2.1.8 Price support systems and other incentives

As previously explained, there currently exists no financial incentives in terms of price support systems for developing OW in Norway. This is an ongoing debate which is yet to be determined and therefore uncertain. In line with the prudent approach, it is assumed the project will not receive any price support incentives for the duration of the lifetime.

It is also assumed that the project will not receive any other financial incentives such as investment grants from institutions such as Enova. Enova is more likely to support infant technologies within floating offshore wind rather than the mature bottom-fixed technologies, as can be seen with the NOK 10,000,000 investment grant for floating wind developer Aker Offshore Wind.

4.1.2.1.9 Decommissioning cost and scrap value

It is assumed that the decommissioning cost and residual scrap value zero each other out. According to Michael Forbes, Refurbishment Manager at Renewable Parts, scrap value and decommissioning costs approximately level each other out in current decommissioned offshore wind projects (Catapult, 2020). Although it is likely to be some small difference for this case, the overall effect on the economic assessment will be minimal and therefore ignored.

4.1.2.2 Economic feasibility results scenario 1: Transmit and sell electricity to the Norwegian power market

Under scenario 1, the electricity produced by the OWF is solely transmitted and sold to the domestic Norwegian power market. From the assumptions presented in table 11 coupled with the WindPRO results from table 10, the various economic methods can be calculated in excel. This includes the resulting cash flow, NPV, IRR, payback period, and LCOE. The detailed calculations from excel can be found in the appendix.

4.1.2.2.1 Payback method

In real 2020 numbers, the project generates an income per year of approx. 961 MNOK (Million NOK). Subtracting the OPEX cost of approximately 314 MNOK, the project generates a positive cash flow EBITDA per year of about 648 MNOK. With an upfront CAPEX investment cost of NOK 13.8 bn (billion), a simple payback calculation shows it takes approx. 21 years to pay back the original investment.

$$Payback\ period = \frac{NOK\ 13{,}832{,}100{,}150}{NOK\ 648{,}166{,}000} = \sim 21\ years$$

4.1.2.2.2 Net present value and Internal rate of return

Table 12 summarizes the resulting NPV and IRR derived from operating cash flow to total capital before taxes and to equity after taxes.

The NPV of operating pre-tax cash flow to total capital minus upfront CAPEX cost has been discounted using the real discount rate of 6%. This results in a negative NPV of approx. NOK -4.9 bn. The pre-tax IRR of 2.36% is less than the required rate of return of 6%, hence explaining the negative NPV.

Table 14 Overview of Net Present Value and Internal Rate of Return results derived from the cash flow. Authors own

Operating cash flow to	NPV	IRR	Required return
Total capital before taxes (real 2020 prices)	-4,910,204,602	2.36%	6%
Equity after taxes and deductions (nominal prices)	261,885,405	6.96%	6.33%

The operating cash flow to equity after taxes and deductions are drastically improved due to the 5-year liner depreciation rule. The discount rate used for the NPV is the after-tax nominal discount rate of 6.33%. Discounting the after-tax cash flow with 6.33% and subtracting the original CAPEX investment provides a positive NPV of approximately 262 MNOK. The after-tax IRR of 6.96% is higher than the required return of 6.33%, thus creating a positive NPV.

It is worth noting that the NPV of total capital before tax is negative because the debt nominal interest rate of 3.5% is below the required return. However, this changes when looking from the equity holder's perspective. The favourable 5 linear depreciation results in a massive cash flow boost in the first 5 years, thereby creating a positive NPV for equity holders.

From this equity standpoint, the project under scenario 1 is economically feasible as NPV is above 0 and the IRR is above the required rate of return.

4.1.2.2.3 Net Present Value profile and Sensitivity analysis

A sensitivity analysis was also undertaken of the pre-tax cash flow to total capital in real prices and after-tax cash flow to equity in nominal prices. The analysis shows the result in NPV by changing each variable independently by ±10%, ±20%, and ±30%. The variables included are changes in CAPEX, OPEX, and net AEP.

A NPV profile of the project is shown in figure 65. It shows the relationship between the projects NPV and the real discount factor. In this case, the NPV in the graph is derived from the cash flow to total capital before taxes in real 2020 prices.

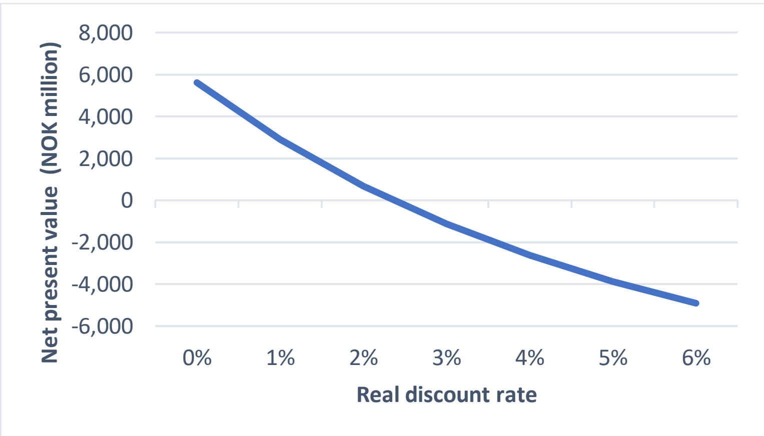


Figure 65 Net present value profile. Authors own

Figure 66 illustrates the resulting NPV by changing the chosen variables CAPEX, OPEX, and net AEP. It can be shown from the figure that the change in CAPEX has the biggest impact on the project NPV due to the steepness of the curve. As an industry burdened with high upfront CAPEX cost, this result is logical. Changes in net AEP will have a near identical impact on the project NPV as the steepness of curve is strikingly similar to the CAPEX curve. By increasing the electricity production, both income and hence generated cash flow will be improved. Last, lower OPEX cost will improve NPV. The project generates a significant positive cash flow per year from the get-go, thus lowering OPEX cost per year further will have a positive impact on NPV.

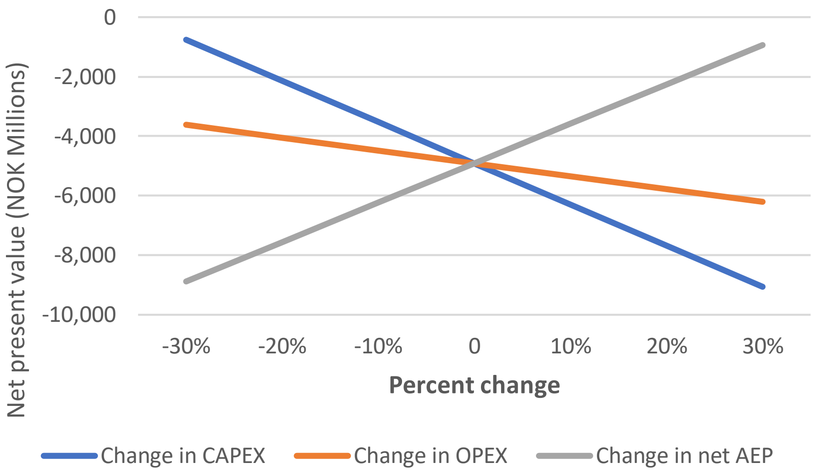


Figure 66 Sensitivity analysis NPV total capital before tax. Authors own

When looking at the NPV to the equity holders in figure 67, the sensitivity analysis illustrates the similar effects to NPV by changing the variables. The difference in this figure is that the NPV to equity holders is positive.

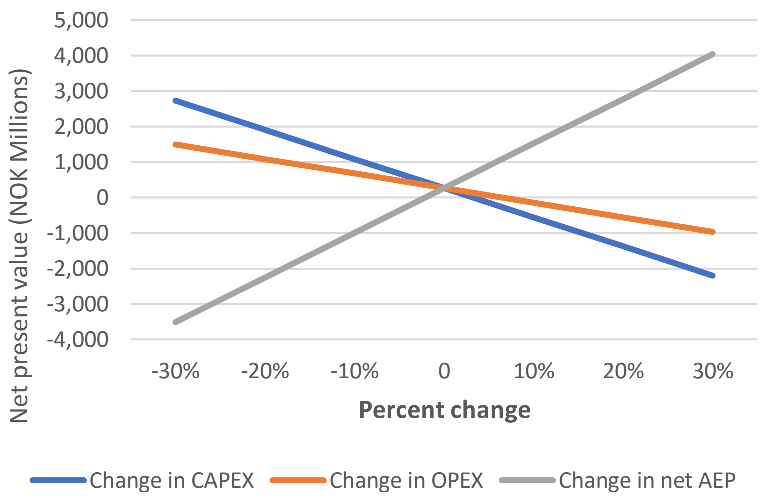


Figure 67 Sensitivity analysis NPV to equity after tax. Authors own

4.1.2.2.4 LCOE

From equation presented in the methods section, the LCOE can be calculated by adding the necessary values from the economic assessment. The calculation is shown below along with the resulting LCOE of 0.52 NOK/kWh, or 52 øre/kWh.

$$LCOE = \frac{13{,}832{,}100{,}150 + \sum_{t=1}^{30} \frac{313{,}500{,}000}{(1+6\%)^t}}{\sum_{t=1}^{30} \frac{2{,}530{,}700}{(1+6\%)^t}} = \frac{521\ NOK/MWh}{1000} = \mathbf{0.52\ NOK/kWh}$$

Figure 68 illustrates the effect of real discount rates on the project LCOE. A lower real discount rate will provide a lower cost of capital and therefore lower LCOE, whilst the opposite effect occurs when raising the real discount rate.

Figure 68 Effect of real discount rates changes on project Levelized Cost of Energy. Authors own

4.1.2.3 Economic feasibility results scenario 2: Transmit and sell electricity to the German power market

Under scenario 2, the electricity produced by the OWF is solely transmitted and sold to the domestic German power market. The assumptions are the same as scenario 1, however the assumed expected average electricity prices in the German power market are higher. The LCOE will be the same as scenario 1 as costs are assumed to be the same.

4.1.2.3.1 Payback method

With higher average electricity prices, the cash flow is higher than in scenario 1. Keeping similar CAPEX costs as assumed, the payback period is calculated at 17 years. This is a payback period improvement of 4 years compared to scenario 1.

$$Payback\ period = \frac{NOK\ 13{,}832{,}100{,}150}{NOK\ 818{,}988{,}250} = \sim 17\ years$$

4.1.2.3.2 Net Present Value and IRR

Table 13 summarizes the resulting NPV and IRR derived from operating cash flow to total capital before taxes and to equity after taxes.

Applying a higher electricity prices to the cash flow calculations, both the NPV and IRRs are improved compared to scenario 1. The NPV of operating pre-tax cash flow to total capital minus upfront CAPEX cost has been calculated at approx. NOK -2,6 bn. An IRR of 4.2% arises from the same cash flow which is below the 6% required rate of return.

Table 15 Net present value and IRR under scenario 2

Operating cash flow to	NPV	IRR	Required return
Total capital before taxes (real 2020 prices)	-2,558,865,174	4.2%	6%
Equity after taxes and deductions (nominal prices)	2,497,911,190	11.84%	6.33%

That said, after taxes and deductions kick in the post-tax cash flow generates a positive NPV of approx. NOK 2.5 bn to the equity stakeholders. In addition, the IRR of 11.84% is greater than the nominal after-tax required rate of return 6.33%, proving the that the investment is attractive for the equity stakeholders. Like scenario 1, the 5-year linear depreciation rule generates a favourable boost to the early cash flows between period 1 and 5.

Therefore, from the economic results the project under scenario 2 is economically feasible to the equity holders as NPV is positive and the IRR is above the required return.

4.1.2.3.3 Sensitivity analysis

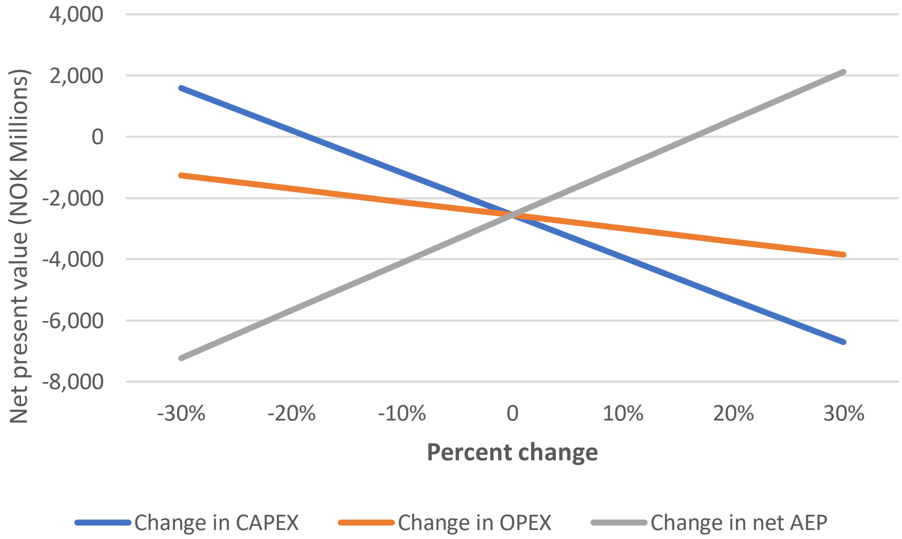


Figure 69 Sensitivity analysis NPV total capital before tax. Authors own

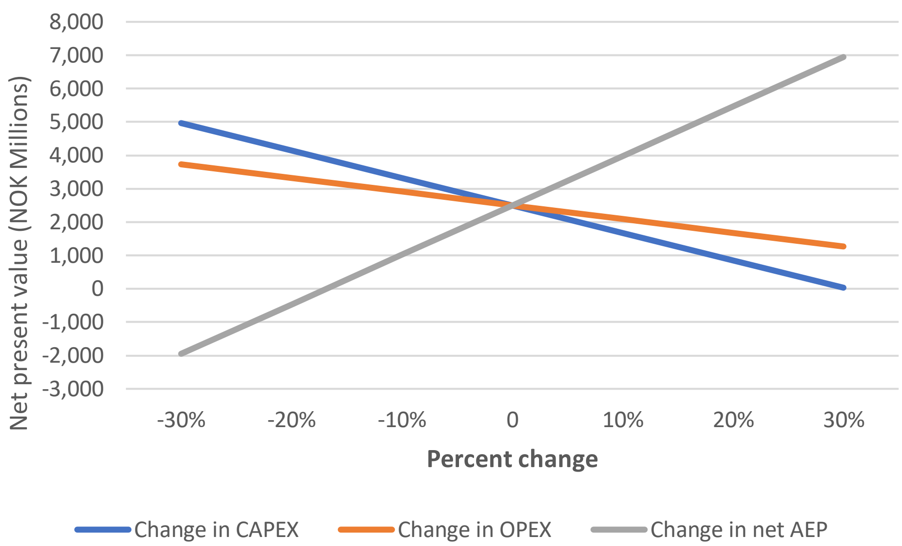


Figure 70 Sensitivity analysis NPV equity after taxes. Authors own

4.1.2.4 Economic feasibility results scenario 3: Transmit and sell electricity to the U.K power market

Under scenario 2, the electricity produced by the OWF is solely transmitted and sold to the domestic U.K power market. The assumptions are the same as scenario 1, however the assumed expected average electricity prices in United Kingdom are the highest of the three scenarios.

4.1.2.4.1 Payback method

Applying the expected average power price for the U.K power market, the yearly cash flow generated in real numbers amounts to approximately 957 MNOK. Dividing this with the total CAPEX investment cost brings yields a payback period of 14 years. This is 7 years faster than scenario 1, and 3 years faster than scenario 2.

$$Payback\ period = \frac{NOK\ 956{,}911{,}400}{NOK\ 13{,}832{,}100{,}150} = \sim 14\ years$$

4.1.2.4.2 Net Present value and IRR

Table 12 summarizes the resulting NPV and IRR derived from operating cash flow to total capital before taxes and to equity after taxes.

The NPV of operating pre-tax cash flow to total capital minus upfront CAPEX cost has been calculated at approx. -660 MNOK. The calculated IRR of 5.55% lies below the 6% required return which explains the negative NPV.

Table 16 NPV and IRR of scenario 3.

Operating cash flow to	NPV	IRR	Required return
Total capital before taxes (real 2020 prices)	-660,376,302	5.55%	6%
Equity after taxes and deductions (nominal prices)	4,303,294,971	15.38%	6.33%

After applying the taxes and deductions, the operating cash flow to equity after taxes and deductions are improved further due to the 5-year liner depreciation rule and higher average electricity prices. The discounted cash flow along with the upfront CAPEX costs generates a positive NPV of NOK 4.3 bn. The after-tax IRR of 15.38% is higher than the required return of 6.33%, thus creating a positive NPV.

As a result, the project under scenario 3 is also economically feasible as NPV is greater than 0 and the IRR is above the required rate of return.

4.1.2.4.3 Sensitivity analysis

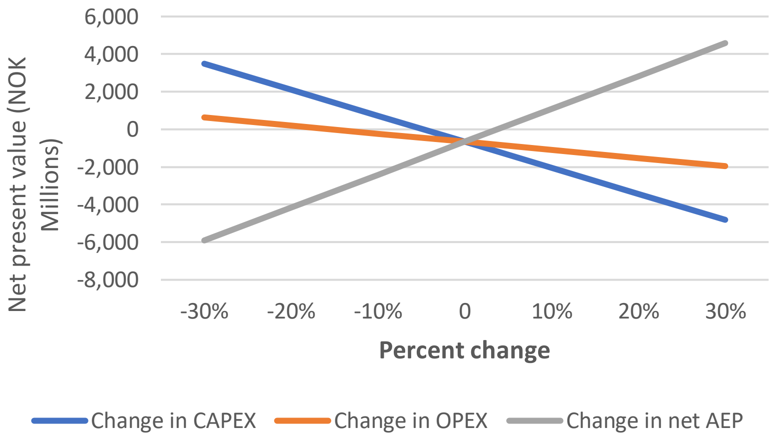


Figure 71 Sensitivity analysis NPV total capital before taxes. Authors own

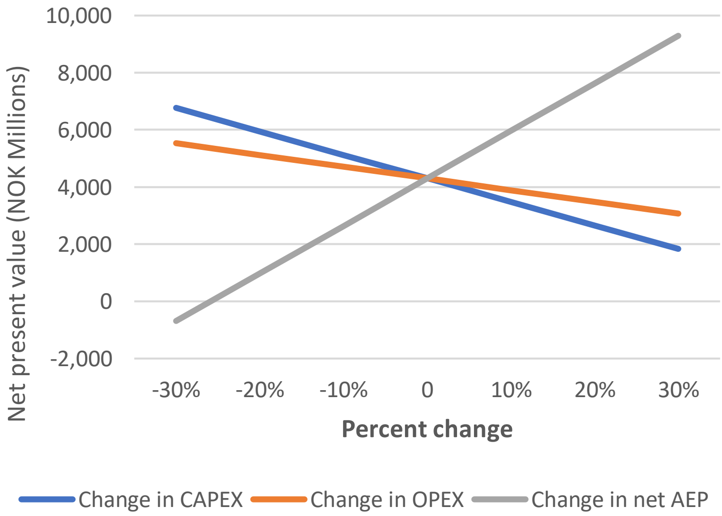


Figure 72 Sensitivity analysis NPV equity after taxes. Authors own

4.1.2.5 Summary of economic results

Table 15 provides a summary of the economic results from each scenario. All the scenarios provide a positive NPV to equity holders and are therefore economically feasible. Comparing the payback period between the scenarios, scenario 3 has the shortest payback period and is therefore more attractive. Scenario 3 also has the highest IRR and NPV between the three, which further concludes that the investor should pursue this option.

Table 17 Summary of economic results under each scenario

Scenario	NPV total capital	IRR total capital	NPV equity	IRR equity	Payback period
1	-4,910,204,602	2.36%	261,885,405	6.96%	21 years
2	-2,558,865,174	4.2%	2,497,911,190	11.84%	17 years
3	-660,376,302	5.55%	4,303,294,971	15.38%	14 years

The sensitivity analysis for all three scenarios illustrate the same relative impact on NPV to total capital before tax and equity after tax by changing the variables CAPEX, OPEX, and net AEP. It was shown that the NPV is highly sensitive to changes in net AEP followed by changes to CAPEX and OPEX. Under scenario 1, a mere 2.5% reduction in net AEP will result in a negative NPV to equity. For scenario 2 and 3, a net AEP decline of 16.5% and 28.5% respectively will result in a negative NPV to equity. Thus, scenario 2 and 3 have a greater cushion for changes in net AEP due to their higher base NPV results. Although less sensitive to changes in net AEP, a similar mindset can be applied to changes in CAPEX cost and OPEX cost. Scenario 1 will only tolerate a 4% increase in CAPEX cost before reaching negative territory, while scenario 2 and 3 tolerates an increase in CAPEX cost of 30% and 40% respectively. The relatively flatter curve of the OPEX variable illustrates that NPV is the least sensitive to changes in OPEX.

5. Discussion

5.1 Regulatory discussion

On the regulatory level, this thesis has described in detail the current regulatory requirements for developing offshore wind in Norway. The word current must be highlighted because this is an ongoing discussion and regulatory details can be amended by the Norwegian government at any point in time. What we do know for certain is that the Norwegian government has opened the areas Sørlige Nordsjø II and Utsira Nord for OW development through the Ocean Energy Law. Developers can submit their license applications from January 1st, 2021 through the Ocean Energy Law. In addition, the Ocean Energy Act describes the licensing procedure which is necessary to obtain for developing OW. Last, other sector-wide relevant laws that need to be considered have been described. In the process of elaborating a notification, it is therefore necessary and recommended that the developer informs several authorities including the County Governor's environmental section (Fylkesmannen miljøvernavdeling), the County municipality's cultural heritage department (Fylkeskommunens kulturminneavdeling), Directorate of Fisheries (Fiskeridirektoratet), and Norwegian Coastal Administration (Kystverket). That said, there are still uncertain elements that needs to be discussed and addressed.

The first uncertainty arises in the licensing process. As per today, the authorities have not informed what specific technical requirements that apply for a notification. This creates uncertainty for the developer when creating the notification, which is a costly process for them. The authorities should rather specify the technical requirements beforehand. For an example, the authorities should include required technical details such as approximate wind farm layout, turbine type, turbine size, fixed or floater foundation, placement of substation, placement of sea cable, onshore installations, etc. This would provide the developer with more certainty in what needs to be included in the notification.

Second, the notification phase is likely to face crowded competition for similar areas and grid connection points. This raises the question over what kind of selection criteria the licensing authorities will base on when awarding certain developers over other. In addition, it raises the question over how the authorities will assign overlapping areas between competing developers. When it comes to overlapping areas, the Ocean Energy Law does provide flexibility to the authorities via terms and conditions it may set upon competing developers. For an example, it is legally possible for the authorities to set a common term for two developers, who are competing for overlapping areas, stating that they will only get a license if they cooperate on a single common OWF. In order to clarify these issues, it is necessary for the authorities to provide transparent selection criteria and rules that will apply. The criteria and rules should therefore be objective, non-discriminatory, and predictable.

OED has released a press statement on the 13th of November stating that a guideline for the licensing process will be available by springtime 2021 which should hopefully provide some more clarity (OED, 2020b). According to Jon Krogvold, engineer at NVE, a task force team at NVE is currently working on their recommendations to this guideline which will be provided to OED (conversation on 28th October 2020). Inquiring about what sort of selection criteria will likely be recommended, Ann Myhrer Østenby at NVE responded with criteria such as a developer's financial strength, experience within offshore development, track record in employee health & safety, and track record within environmental mitigation measures (conversation on 1st October, 2020). She also pointed out that the authorities will likely choose the more realistic planned OWF which has a higher chance of success. The likely selection criteria do make sense in terms of increasing the chances of success for a planned OW. Nothing is worse than a bankrupt developer failing to finalize an OWF. However, such criteria clearly favour developed companies with a long history of offshore experience such as Equinor and Aker. This could become discriminatory towards lesser developed OW companies who might have better ideas but will not come to fruition due to the selection criteria. Also, it can be argued that choosing an OW based on its probability of success becomes a subjective opinion. Luckily, OED and NVE possess in-depth knowledge of the OW industry which should provide them with objective decision-making, but their decisions still needs to be clearly explained to the developers. Hopefully, the guideline released in springtime 2021 will provide some clarity. In the meantime, it does not make much sense for developers to apply beforehand without the guideline. The delay is not welcomed by developers hoping to kick-start their multi-billion investment projects and only adds to the uncertainty. According to Christian Berg, Financial Office at Wilhelmsen, the regulatory framework is currently far behind the current rapid OW development seen across Europe (conversation 8th December 2020). Norway risks losing out to potential investors if the regulatory framework remains unpredictable. Thus, transparency from the authorities and ongoing dialogue regarding the selection criteria is key in order to not scare off any potential investments and thus hampering the development of OW in Norway.

Another regulatory headache for OW development is the uncertainty surrounding the integration into a potential common EU power market via export cables. According to OED, the Ocean Energy Law was initially developed with a focus on transmitting electricity from a potential OWF to a single connection point in Norway, foreign country, or to electricity its oil fields (Mollestad, 2020). In this case, the Norwegian Transmission System Operator Statnett would thus be able to set the terms and conditions for the Norwegian grid connection. Statnett is not required to commit to a certain grid connectivity date, which can provide uncertainty for the OWF developers. This problem aside, a possible dilemma rather lies in the export of electricity to Europe via a meshed grid island. The Ocean Energy Law is rather unclear when it comes to connecting to European energy hubs (Mollestad, 2020). With growing renewable energy sources entering the European energy mix, the European power markets will transform from a centralized system to a more decentralized system. This transformation has resulted in the EU desiring a closer integration and harmonization between the members power market (European Commission, 2020). This strategy includes a closer cooperation between each country members Transmission System Operators (TSO) with the end goal of creating a single European market for balancing the electricity (European Commission, 2020). As part of the EEA, Norway is obligated to cooperate within the European TSO regulations if Norwegian power producers export power to EU (NVE, 2019b). Integrating into a common European meshed grid network will therefore require regulatory clarifications. It raises the question of who will own the meshed grid infrastructure? Who will be the TSO for the meshed grid network between multiple countries? How this interconnected European grid system network between different European OWFs will be organized is certainly be a complex tax and is beyond the scope of this thesis, but it is worth mentioning here as a regulatory uncertainty for the proposed OWF in Norway.

5.2 Technical discussion

This thesis has described that it is technically feasible to build the planned OWF in the area. However, this is based on limited information and data. The site characteristics are highly uncertain due to the lack of information. The area has not been thoroughly explored. The seabed and water depth has been given a rough description which is likely not accurate. Any changes to the site characteristics would require a reassessment of the technical parameters. In addition, the lack of engineering skills has left the author reliant on the expertise of others, which also creates uncertainty.

Further, it is uncertain whether the connection points assessed are technically realistic. There is uncertainty surrounding the domestic transmission grid bottlenecks in each country. If there are bottlenecks in the domestic grid, it is likely to be very difficult for the OWF to be able to transmit the electricity into the grid. Without any upgrades to the grid, the increasing implementation of other renewable energy sources will further exacerbate these bottlenecks. According to Statnett (2020), there will be great uncertainty regarding the current transmission bottlenecks in the German power transmission lines between the North and South regions for the next 20 years. How Germany and other countries handles these transmission bottlenecks is a decisive factor for whether the grid can handle the extra electricity produced from the OWF. This thesis has assumed that there are no bottlenecks in the Norwegian, German, or U.K domestic grid. In reality, bottlenecks in the grid can become problematic for the proposed OWF if the receiving countries fail to upgrade their respective domestic grid lines.

5.2 Economical discussion

Given the assumptions, the results from the economic analysis concluded that all three scenarios ended up with positive NPV to equity holders. Given a real discount rate of 6%, it is logical that the NPV to total capital turns negative due to the 3.5% interest return on debt. The nominal pre-tax IRR to total capital is higher than the nominal interest rate of 3.5%, but this benefit will accrue solely to the equity holders. Therefore, the project is economically feasible to the equity holders regardless of which scenario the developer chooses. The project in each scenario generates positive net yearly cash flow throughout its 30-year lifetime. With a solid net AEP of approximately 2.5 TWh, annual income is greater than the sum of OPEX and debt repayment costs. In addition, NPV and IRR to equity holders is further enhanced when applying the 5-year linear depreciation rule which significantly improves the after-tax cash flow for the first five years in each scenario. When comparing between the three scenarios, scenario 3 has the highest IRR and NPV because of higher average electricity prices expected for the U.K power market. Scenario 3 should therefore be the preferred option. The sensitivity analysis also illustrated that the NPV scenario 3 has more leeway when it comes to changes in OPEX, CAPEX, or net AEP. In addition, scenario 2 has a higher IRR and NPV than scenario 1. These results argue for transmitting and selling the electricity to the U.K or German power market rather than the Norwegian market in order to maximize the projects economic returns. The LCOE, which is the same for each scenario due to assumed similar costs, was calculated at 0.52 NOK/kWh. This is in line with the expected downwards trajectory of LCOE for bottom fixed OW projects. According to predictions by Thema Consulting (2020), average LCOE for bottom-fixed OW projects commissioned by the year 2030 will be lie in the interval between 0.43 and 0.64 NOK/kWh. Although the economic results lay out a rosy picture of the OW project, there are several uncertain factors which need to be discussed.

First, the underlying CAPEX and OPEX cost data does not represent a highly accurate estimation for the OWF project assessed in this thesis. For instance, NVE's CAPEX and OPEX cost per MW installed data is based on an average from OWF currently in operation and was estimated in the year 2019. The average nature of the cost estimations will not accurately represent the cost for the specific OWF site that is assessed in this thesis. As NVE (2019a) pointed out, costs for developing OW in Norway is likely higher than the average cost because of the water depth and complicated seabed conditions. That said, their estimations are somewhat outdated and fail to capture the expected rapid cost reductions. To remedy any inaccuracies and account for future cost reductions, the Belgian OW developer Parkwind was able to provide expected CAPEX costs for similar OW projects that are under pre-phase development. However, Parkwind's estimations can also be argued to be highly uncertain as projects at these sizes tend to go over expected budgets. The cost data applied to the economic assessment can therefore be classified as rather optimistic. That said, the sensitivity analysis undertaken for scenario 2 and 3 illustrated that even with a 30% increase in CAPEX investment cost the NPV would still be significantly positive for both cases. It would be beneficial to gather more cost data from different companies, but this has proven to be difficult due to the secrecy of such data. Therefore, there is a high degree of uncertainty and credibility to the cost data.

On the income side of the assessment, the average electricity prices applied to the economic assessment is associated with great uncertainty. Based on the NVE (2020) analysis, the average prices depend on a range of assumptions regarding the future Nordic and European power system. Despite assumed energy efficiency measures, electricity consumption in Norway, Germany, and U.K will gradually increase towards 2040 as the countries increase the electrification their industry and transportation sector. In line with EU's climate policy goals, electricity supply in Europe will shift from coal and gas to increasingly more variable renewable electricity such as wind and solar. Generally, it can be expected that a large covariation in the production of wind energy will affect the profitability of OWF in Europe because simultaneous strong winds will lead to lower spot prices. Therefore, it can be argued that an increase in wind power production for the project case area will face lower electricity prices as there are several other competing European OWFs facing the same simultaneous wind resources. However, NVE (2020) assumes in their analysis that there will be an increase in flexibility solutions such as hydrogen production and battery storage which will help stabilize the electricity prices. Further, an expected increase in sea cable transmission network will open more markets with different price regimes which will help improve the profitability. In all, the

European and Nordic power market will undergo a significant transformation in the next two decades which will have a highly uncertain net impact on electricity prices for each power market. Despite the high uncertainty, this master thesis has calculated income prudently by using the lower-bound predicted average electricity prices for each market.

6. Conclusion and recommendations

This thesis has undertaken a technic-economic analysis along with regulatory requirements for developing a 550MW offshore wind farm in Sørlige Nordsjø II. An increasing cooperation and integration into EU climate politics offers both challenges and opportunities for Norway. EU's proposed ambitious strategy for offshore wind development in the North Sea region will provide a tremendous opportunity for Norway's struggling oil and gas sector. This opportunity was manifested with the opening of Sørlige Nordsjø II for developing offshore wind in Norway. However, it is important for developers to analyse the feasibility of developing an offshore wind farm in terms of regulatory, technical, and economical before this adventure can begin.

Sørlige Nordsjø II possesses a vast untapped potential for offshore wind development. The area offers some of the strongest wind resources in Europe. In addition, its location houses several potential grid connectivity points for a potential offshore wind farm. However, the area poses several technical challenges for which the potential offshore wind farm needs to consider. Although in harsh sea conditions with water depths between 60-70m, it was found to be technically feasible to use a four-legged bottom fixed foundation. The foundation is optimal for the seabed in the area which is characterized by sand and clay. Covering an area of $44\ km^2$, the 550MW wind farm is optimally laid out via 66kv array cables connected between 55 Siemens Gamesa SG 11-193 DD Flex turbines, each with a rated capacity of 11MW. The electricity produced will be transformed and transmitted via a HVDC substation in order to reduce losses. Along with the wind data provided by Stormgeo, the offshore wind farm was simulated in WindPRO and was used to calculate a net AEP of 2.5 TWh. It is therefore technically feasible to develop a 550MW offshore wind farm in Sørlige Nordsjø II by using the current technology available. That said, it is recommended that the developer examines the site much more thoroughly before drawing any conclusions for the technical parameters.

From the calculated net AEP, it can be concluded that under the right circumstances, developing a 550 MW offshore wind farm in Sørlige Nordsjø II is economically feasible for all the three scenarios assessed. Under given assumptions, all three scenarios generated a positive NPV and IRR greater than the required returns. Scenario 1 resulted in a positive NPV to equity after taxes of approx. 262 MNOK with an IRR of 6.9%. Scenario 2 resulted in a positive NPV to equity after taxes of NOK 2,5 bn with an IRR of 11.8%. Finally, scenario 3 resulted in a positive NPV to equity after taxes of approx. NOK 4,3 bn with an IRR of 15.3%. From the economic analysis, it was shown that greater economic returns can be obtained by exporting the produced electricity to either Germany or United Kingdom rather than transmitting the electricity into Norway. Of the three scenarios, transmitting and selling the produced electricity into the United Kingdom would provide the highest returns to the equity holders. Last, the LCOE for the offshore wind farm was calculated at 0.52 NOK/kWh. Therefore, the proposed 550MW offshore wind farm is economically feasible and in line with expected cost reductions.

The regulatory and legal requirements for offshore wind development in Norway are laid out in the Ocean Energy Law and the Ocean Energy Act. Other sector relevant laws and authorities are also required to be considered when developing offshore wind at Sørlige Nordsjø II. That said, OED plans to release a guideline in spring 2021 which hopefully to clarifies these regulatory issues. Therefore, the regulatory and legal framework in Norway enables the development of an offshore wind farm in Sørlige Nordsjø II but there remain some uncertain factors such as potential export connection to a meshed European grid network. It is therefore recommended that the developer awaits submitting a license application until the OED publishes the license guidelines in spring 2021.

As a response to the economic results, it would be recommended that the 550 MW offshore wind farm is technically designed to transmit and sell the produced electricity into the U.K power market. In addition to facing predicted higher average electricity prices, the U.K power market is less constrained by bottlenecks in their domestic grid lines. Predicted average electricity prices are satisfactory in the German power market, however there is too much uncertainty and risks associated with the bottlenecks in their domestic grid lines. The economic feasibility of transmitting and selling into the Norwegian power market is highly questionable due to the abundance of hydro power and expected domestic grid bottlenecks. Political support for transmitting the electricity into the Norwegian market is also questionable. Therefore, it is recommended that the developer ignores the Norwegian power market entirely. Finally, it is recommended that the developer investigates the potential to connect the offshore wind farm into a meshed grid island that the EU proposes. Such an island would provide much more flexibility to transmit and sell the electricity where prices are the highest.

In addition, it is highly recommended that the developer investigates excess storage solutions for the 550MW offshore wind farm. A large covariation in the production of wind energy in Europe will lead to lower spot prices when the wind blows strongly. In this situation, it would be economically beneficial if the offshore wind farm can use the excess electricity for producing hydrogen via electrolysis. Another storage solution worth investigating is to use the excess electricity in a pumped-hydro storage plant.

Finally, it is necessary to emphasize that the results in this thesis are based on highly uncertain data and information. It is necessary to add further research with better quality data in order to undertake a more detailed economic and technical assessment. In addition, this thesis should also be further supported by an assessment into the environmental concerns surrounding the proposed offshore wind farm.

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8. Appendix

PARK - Main Result

Wake Model N.O. Jensen (RISØ/EMD)

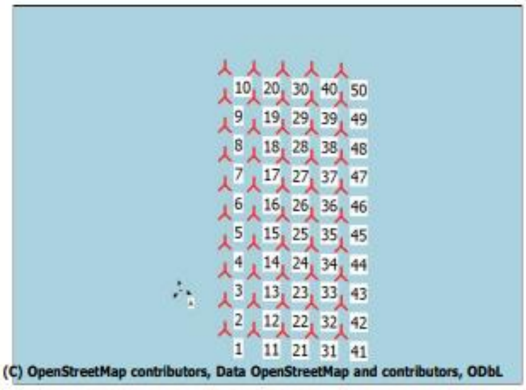
Calculation performed in UTM (north)-WGS84 Zone: 31
At the site centre the difference between grid north and true north is: 0,6°

Power curve correction method
New windPRO method (adjusted IEC method, improved to match turbine control) <RECOMMENDED>
Air density calculation method
Height dependent, temperature from climate station
Station: LISTA FYR
Base temperature: 7,7 °C at 14,0 m
Base pressure: 1013,3 hPa at 0,0 m
Air density for Site center in key hub height: 0,0 m + 100,0 m = 1,244 kg/m³ -> 101,6 % of Std
Relative humidity: 0,0 %

Wake Model Parameters
Wake decay constant 0,050 DTU default offshore

Wake calculation settings

Angle [°]			Wind speed [m/s]		
start	end	step	start	end	step
0,5	360,0	1,0	0,5	30,5	1,0



Scale 1:200 000
New WTG   Meteorological Data

Key results for height 100,0 m above ground level

Terrain UTM (north)-WGS84 Zone: 32

	Easting	Northing	Name of wind distribution	Height [m]	Type	Wind energy [kWh/m²]
A	244872	6304030	EmdConwx_N56.810_E004.820 (2)	100,0	WEIBULL	8534

Calculated Annual Energy for Wind Farm

WTG combination	Result PARK [MWh/y]	Result-10,0% [MWh/y]	GROSS (no loss) Free WTGs [MWh/y]	Wake loss [%]	Specific results¤) Capacity factor [%]	Mean WTG result [MWh/y]	Full load hours [Hours/year]	Mean wind speed @hub height [m/s]
Wind farm	2811879,2	2530691,2	3103210,2	9,4	52,5	50613,8	4601	10,4

¤) Based on Result-10,0%

Calculated Annual Energy for each of 50 new WTGs with total 550,0 MW rated power

Links	WTG type Valid	Manufact.	Type-generator	Power, rated [kW]	Rotor diameter [m]	Hub height [m]	Power curve Creator	Name	Annual Energy Result [MWh/y]	Result-10,0% [MWh/y]	Wake loss [%]	Free mean wind speed [m/s]
1 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	60105,8	54095	3,2	10,43
2 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58855,8	52970	5,2	10,43
3 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58219,9	52398	6,2	10,43
4 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57884,1	52096	6,7	10,43
5 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57682,8	51915	7,1	10,43
6 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57594,3	51835	7,2	10,43
7 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57553,9	51799	7,3	10,43
8 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57588,2	51829	7,2	10,43
9 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57728,9	51956	7,0	10,43
10 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58170,8	52354	6,3	10,43
11 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58856,7	52971	5,2	10,43
12 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57078,4	51371	8,0	10,43
13 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56188,0	50569	9,5	10,43
14 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55727,6	50155	10,2	10,43
15 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55506,9	49956	10,6	10,43
16 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55410,4	49869	10,7	10,43
17 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55385,8	49847	10,8	10,43
18 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55523,4	49971	10,5	10,43
19 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55879,3	50291	10,0	10,43
20 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56759,4	51083	8,5	10,43
21 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58262,6	52436	6,1	10,43
22 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56271,3	50644	9,3	10,43
23 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55227,1	49704	11,0	10,43

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PARK - Main Result

...continued from previous page

	WTG type						Power curve		Annual Energy			
Links	Valid	Manufact.	Type-generator	Power, rated [kW]	Rotor diameter [m]	Hub height [m]	Creator	Name	Result [MWh/y]	Result-10,0% [MWh/y]	Wake loss [%]	Free mean wind speed [m/s]
24 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54731,2	49258	11,8	10,43
25 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54464,2	49018	12,2	10,43
26 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54372,2	48935	12,4	10,43
27 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54397,3	48958	12,4	10,43
28 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54581,2	49123	12,1	10,43
29 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55072,8	49566	11,3	10,43
30 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56158,8	50543	9,5	10,43
31 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58180,6	52363	6,3	10,43
32 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56198,7	50579	9,5	10,43
33 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55170,1	49653	11,1	10,43
34 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54632,5	49169	12,0	10,43
35 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54402,2	48962	12,3	10,43
36 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54315,8	48884	12,5	10,43
37 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54336,8	48903	12,5	10,43
38 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	54586,3	49128	12,0	10,43
39 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55118,5	49607	11,2	10,43
40 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56239,2	50615	9,4	10,43
41 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	58655,4	52790	5,5	10,43
42 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56924,9	51232	8,3	10,43
43 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55989,2	50390	9,8	10,43
44 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55511,5	49960	10,6	10,43
45 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55273,9	49747	10,9	10,43
46 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55198,6	49679	11,1	10,43
47 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55247,1	49722	11,0	10,43
48 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	55495,5	49946	10,6	10,43
49 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	56054,2	50449	9,7	10,43
50 A	No	Siemens Gamesa	SG 10.0-193 DD-11000	11000	193,0	120,0	USER	Power curve (0)	57109,3	51398	8,0	10,43

WTG siting

	UTM (north)-WGS84 Zone: 32			
	Easting	Northing	Z [m]	Row data/Description
1 New	246313	6302588	0,0	0,0°, 1000,0 m
2 New	246374	6303587	0,0	
3 New	246434	6304586	0,0	
4 New	246495	6305585	0,0	
5 New	246556	6306584	0,0	
6 New	246617	6307582	0,0	
7 New	246677	6308581	0,0	
8 New	246738	6309580	0,0	
9 New	246799	6310579	0,0	
10 New	246860	6311577	0,0	
11 New	247310	6302501	0,0	0,0°, 1000,0 m
12 New	247370	6303500	0,0	
13 New	247431	6304498	0,0	
14 New	247491	6305497	0,0	
15 New	247552	6306496	0,0	
16 New	247612	6307495	0,0	
17 New	247673	6308494	0,0	
18 New	247733	6309492	0,0	
19 New	247794	6310491	0,0	
20 New	247854	6311490	0,0	
21 New	248307	6302413	0,0	0,0°, 1000,0 m
22 New	248367	6303412	0,0	
23 New	248427	6304411	0,0	
24 New	248487	6305410	0,0	
25 New	248548	6306408	0,0	
26 New	248608	6307407	0,0	
27 New	248668	6308406	0,0	

PARK - Main Result

...continued from previous page

	UTM (north)-WGS84 Zone: 32			
	Easting	Northing	Z [m]	Row data/Description
28 New	248728	6309405	0,0	
29 New	248789	6310404	0,0	
30 New	248849	6311402	0,0	
31 New	249303	6302326	0,0	0,0°, 1000,0 m
32 New	249363	6303324	0,0	
33 New	249423	6304323	0,0	
34 New	249483	6305322	0,0	
35 New	249543	6306321	0,0	
36 New	249603	6307320	0,0	
37 New	249663	6308318	0,0	
38 New	249723	6309317	0,0	
39 New	249783	6310316	0,0	
40 New	249844	6311315	0,0	
41 New	250300	6302238	0,0	0,0°, 1000,0 m
42 New	250360	6303237	0,0	
43 New	250420	6304236	0,0	
44 New	250479	6305234	0,0	
45 New	250539	6306233	0,0	
46 New	250599	6307232	0,0	
47 New	250659	6308231	0,0	
48 New	250719	6309230	0,0	
49 New	250778	6310228	0,0	
50 New	250838	6311227	0,0	

Kontantstrøm til total kapital før skatt (reele priser 2020 kr)													
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Sum inntekter		942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680	942,432,680
Sum driftskostnader (OPEX)		313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000	313,500,000
Driftsresultat (EBITDA)		**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**
Investerings kostnader (CAPEX)	-13,832,100,150												
Kontantstrøm til totalkapital før skatt	**-13,832,100,150**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**	**628,932,680**
Kontantstrøm til totalkapital før skatt (i lø	**-13,832,100,150**	**641,511,334**	**654,341,560**	**667,428,391**	**680,776,959**	**694,392,498**	**708,280,348**	**722,445,955**	**736,894,875**	**751,632,772**	**766,665,427**	**781,998,736**	**797,638,711**

Kontantstrøm til egenkapital før skatt (løpende priser)														
Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Sum inntekter		961,281,334	980,506,960	1,000,117,099	1,020,119,441	1,040,521,830	1,061,332,267	1,082,558,912	1,104,210,090	1,126,294,292	1,148,820,178	1,171,796,582	1,195,232,513	1,219,137,164
Sum driftskostnader (OPEX)		319,770,000	326,165,400	332,688,708	339,342,482	346,129,332	353,051,918	360,112,957	367,315,216	374,661,520	382,154,751	389,797,846	397,593,803	405,545,679
Driftsresultat løpende priser (EBITDA)		**641,511,334**	**654,341,560**	**667,428,391**	**680,776,959**	**694,392,498**	**708,280,348**	**722,445,955**	**736,894,875**	**751,632,772**	**766,665,427**	**781,998,736**	**797,638,711**	**813,591,485**
Investeringskostnader (CAPEX)	-13,832,100,150													
Kontantstrøm til totalkapital før skatt (løp	**-13,832,100,150**	**641,511,334**	**654,341,560**	**667,428,391**	**680,776,959**	**694,392,498**	**708,280,348**	**722,445,955**	**736,894,875**	**751,632,772**	**766,665,427**	**781,998,736**	**797,638,711**	**813,591,485**
Lån/gjeld - serielån														
Lån og restlån	9,682,470,105	9,359,721,102	9,036,972,098	8,714,223,095	8,391,474,091	8,068,725,088	7,745,976,084	7,423,227,081	7,100,478,077	6,777,729,074	6,454,980,070	6,132,231,067	5,809,482,063	5,486,733,060
Årlige avdrag		322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004	322,749,004
Årlig renter		338,886,454	327,590,239	316,294,023	304,997,808	293,701,593	282,405,378	271,109,163	259,812,948	248,516,733	237,220,518	225,924,302	214,628,087	203,331,872
Total låneforplitelser		**661,635,457**	**650,339,242**	**639,043,027**	**627,746,812**	**616,450,597**	**605,154,382**	**593,858,166**	**582,561,951**	**571,265,736**	**559,969,521**	**548,673,306**	**537,377,091**	**526,080,876**
Kontantstrøm til egenkapital før skatt (løp	**-4,149,630,045**	**-20,124,124**	**4,002,318**	**28,385,365**	**53,030,147**	**77,941,902**	**103,125,967**	**128,587,789**	**154,332,923**	**180,367,036**	**206,695,906**	**233,325,430**	**260,261,620**	**287,510,609**
Linær avskrivning 5 år		2,766,420,030	2,766,420,030	2,766,420,030	2,766,420,030	2,766,420,030								
Skattepliktig inntekt		-2,463,795,150	-2,439,668,708	-2,415,285,662	-2,390,640,879	-2,365,729,125	425,874,970	451,336,792	477,081,927	503,116,039	529,444,910	556,074,434	583,010,623	610,259,613
Skattebetaling med 5 års avsirkvining		-542,034,933	-536,727,116	-531,362,846	-525,940,993	-520,460,407	93,692,493	99,294,094	104,958,024	110,685,529	116,477,880	122,336,375	128,262,337	134,257,115
Kontantstrøm til egenkapital etter skatt (l	**-4,149,630,045**	**521,910,809**	**540,729,434**	**559,748,210**	**578,971,141**	**598,402,309**	**9,433,473**	**29,293,695**	**49,374,899**	**69,681,507**	**90,218,026**	**110,989,055**	**131,999,283**	**153,253,494**

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