Norwegian School of Economics

Bergen, Spring 2022

An accounting-based profitability analysis of deploying offshore wind at Sørlige Nordsjø II

A new North Sea adventure or a renewable energy fallacy?

Eivind Trym Wikshåland and Sondre Arne Hoff

Supervisor: Gunnar Eskeland

Master thesis, Economics and Business Administration

Major: Business Analysis and Performance Management, Financial Economics

NORWEGIAN SCHOOL OF ECONOMICS

Acknowledgements

We would like to extend our deepest gratitude to Professor Gunnar Eskeland for his encouragement and supervising throughout this semester. First, for opening our minds to the vast topic opportunities within offshore wind. Second, for letting us establish our thesis on our own premises and connecting us with recognized people. Additionally, a great thanks goes to Professor Arnt Ove Hopland at the Norwegian School of Economics for help with reviewing and structuring the thesis.

This master project would not have been possible without the contribution from Professor Gordon Hughes at the University of Edinburgh. We are thankful for Hughes sharing his decades long expertise, and for devoting several hours to provide us with valuable data and knowledge.

We would further like to give our thanks to Bergen Offshore Wind (BOW) at the University of Bergen. Firstly, Joachim Reuder for giving technical expertise on how to best incorporate wind theory in our economic model. Secondly, Etienne Cheynet for providing wind data and computational aid to incorporate it in our model and lastly, Ida Marie Solbrekke.

Working with this thesis has given us valuable insight into an exciting industry emerging in Norway. It has been motivating working with a topic influencing media headlines these past months.

Finally, an appreciation goes to family and loved ones for support and feedback in demanding periods, helping us stay on track when issues arose.

Norwegian School of Economics

Bergen, May 2022

Eivind Trym Wikshåland Sondre Arne Hoff

Abstract

Offshore wind has received a great amount of attention the last decade, with industry initiatives underpinning development across nations. European offshore wind auction strike prices have decreased drastically, indicating falling costs in the industry. Additionally, cost figures in the literature are often based on public domain sources rather than actual costs from financial statements. The former is prone to distortion, yielding uncertainty regarding its reliability. Thus, this thesis reviews historic project costs in the North Sea using audited accounts from 38 UK offshore wind farms' special purpose vehicles (SPV). A profitability analysis of deploying 1400 MW capacity at Sørlige Nordsjø II (SNII) in 2030 has been conducted, assuming a radial connection to the Norwegian mainline grid NO2. Doing so, a discounted cash flow model (DCF) combined with Monte Carlo Simulation (MCS) has been applied. Additionally, a Levelized Cost of Energy (LCOE) for SNII has been computed and compared against literature estimates.

This paper shows that offshore wind development for the first phase of Sørlige Nordsjø II is unprofitable. With certain optimistic assumptions, our good case scenario barely obtained a positive net present value (NPV). LCOE was to some degree in line with other literature estimates. Higher costs in audited accounts compared to reported figures in addition to complicated site characteristics contributed to the negative results. Consequently, significant technological cost developments, more efficient supply chain operations as well as a substantial growth in electricity price are needed to overcome profitability obstacles. As of this, developing SNII is unattractive for investors under current assumptions. Subsidies are likely needed, albeit at a cost for the government. On the other hand, this paper provides concluding recommendations to seek other project solutions, namely hybrid cables to trade partners. Not being profitable with a radial connection to Norway, potential higher electricity prices across borders might increase the likelihood of profitability.

Abbreviations and other key elements

AEP	Annual Energy Production
CAPEX	Capital Expenditures
COD	Commercial Operation Date
DCF	Discounted Cash Flow
GW	Gigawatt
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
LCOE	Levelized Cost of Energy
LFA	Life Cycle Assessment
MCS	Monte Carlo Simulation
NPV	Net Present Value
OFTO	Offshore Transmission Owner
OPEX	Operational Expenditures
OW	Offshore wind
OWF	Offshore Wind Farm
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital

Applied exchange rates[1]

EUR/NOK	9,711
GBP/NOK	11,479
USD/GBP	0,762
USD/NOK	8,748

[1] Spot exchange rates from the central bank of Norway, 2:15 pm CET, March 31st 2022 https://www.norges-bank.no/en/topics/Statistics/exchange_rates/

Table of contents

List of figures

List of tables

1. Introduction

Climate change and the transition to renewable energy sources have emerged as a pressing topic. Thus, governments and organizations put out ambitious climate goals and deployment targets to secure a low emission future. In 2021, United Nations' (UN) climate change conference COP26 gathered world leaders and policy makers from all over the world. Here, agreements were made to secure a maximum global temperature increase of 1,5 C degrees and net zero emissions by 2050 (UN, 2022). Coal and other emission heavy industries are set to be replaced by low emission energy sources by the upcoming decades. This implies massive investments across nations. IEA (2021) estimate a renewable energy share increasing from below 30% in 2020 to over 40% in 2030. To achieve this, investments in renewable energy such as wind is needed. According to IRENA (2019), onshore and offshore wind (OW) can contribute to 35% of energy needs by 2050, whereas OW being the third largest energy source. To materialize this, the European Commission announced ambitious deployment targets in 2020. This includes at least 60 GW offshore wind capacity within 2030, and 300 GW within 2050, requiring an estimated €800 billion in investments (EC, 2020). Knowing that current installed capacity as of year end 2021 comprised of 28 GW in Europe and 56 globally, European installed capacity needs to double within 2030 (WindEurope, 2022; Statista, 2022).

1.1 Background and motivation

The Norwegian government has been reluctant to state any official industry offshore wind deployment goal until recently. In 2020, they announced the opening of two offshore wind sites in the Norwegian continental shelf; Utsira Nord and Sørlige Nordsjø II (SNII) (OED, 2020). Recently, the Norwegian government further emphasized the offshore wind ambition, before announcing a national deployment goal of 30 GW within 2040 (Norwegian Government, 2022b). However, high upfront investments are required to deliver on such targets. Thus, understanding cost structures and the economic feasibility of building an offshore wind farm (OWF) is important. IEA (2019) states that approximately 40% of total OWF costs have synergies with the oil and gas sector. Hence, Norway may have untapped opportunities to benefit from decades of offshore oil and gas activity and competence.

The OW auction strike price results in Europe have added further curiosity regarding the area of offshore wind. This is the price developers offer per unit of electricity to realize the project (IRENA, 2015).European strike prices have fallen drastically from a level of $185/MWh for a project with commercial operation date (COD) in 2019, to $47/MWh with expected COD in 2026. A brief overview of strike prices obtained in different European countries can be seen in table 1.1.

As strike prices decrease, there seems to be growing confidence among industry players and investors that offshore wind is moving towards a subsidy free era (IEA, 2019). As a result, this thesis seeks to evaluate historic and current cost trends in order to unveil the actual profitability of developing current and future OWFs.

Included transmission cost			Excluded transmission cost		
Project	**Strike price ($/MWh)**	**Expected COD**	**Project**	**Strike price ($/MWh)**	**Expected COD**
United Kingdom			**Germany**		
Beatrice	185	2019	Baltic Eagle	74	2023
East Angelia 1	152	2020	Gode wind 3	68	2024
Triton Knoll	95	2021	Gode wind 4	112	2023
Moray East	73	2022	**Netherlands**		
Hornsea 1	178	2022	Borssele I/II	83	2020
Hornsea 2	76	2022	Borssele III/IV	62	2021
Neart na Gaoithe	148	2023	**Denmark**		
Dogger bank A	51	2024	Horns Rev 3	118	2020
Dogger bank B	54	2025	Kriegers Flak	57	2021
Dogger bank C	54	2025	Vesterhav Nord/Syd	73	2023
Seagreen	54	2025			
Sofia	47	2026	**France**		
			Dunkirk	50	2026

Table 1.1 *Offshore wind strike price observed in different countries show a falling trend.*
Source: Authors own. Numbers obtained from (IEA, 2019)

1.2 Research question

Presently, offshore wind development costs as presented in the literature seem to be heavily reliant on public domain sources rather than actual cost data as presented by Aldersey-Williams et al. (2019) and Hughes (2020). Motivated by the opportunity of using audited accounts to show actual project costs, we want to examine how offshore wind farms' financial statements may apply to a planned project. As such, our research question is:

What is the long-term profitability and marginal cost of a potential offshore wind farm on the Norwegian continental shelf? A case study of Sørlige Nordsjø II.

Our work will hopefully contribute to the public debate regarding the profitability of offshore wind farms, free of any distorted values. To the authors knowledge, a profitability analysis of Sørlige Nordsjø II based on audited accounts is yet to be conducted. The following chapter will present a literature review of previous work on the topic, serving as a starting point for our thesis.

2. Litterature review

Extensive literature exists on the topic of offshore wind farm deployment. Following the Norwegian Water Resources and Energy Directorate's[2] strategic envirionmental assesment in 2012, the sector has gained momentum and interest (NVE, 2012). Since 2011, the number of mentions of "offshore wind" has increased from 3 to 17 in IEAs annual world energy outlook (IEA, 2011; IEA, 2021). In line with the emergence of offshore wind and other renewable technologies, the need for appropriate and reliable cost models to compare the cost level is crucial. Liu et al. (2021) are among others that have conducted a literature review of different decision-making methodologies applied in OWF feasibility studies (Liu et al., 2021). They stress the importance of including technical and economical parameters such as type of turbine and foundation technology. To complete a fair economic assessment of any offshore wind plant, Johnston et al. (2020) further point out that understanding the cost drivers of building and operating projects are vital. These need to be understood and taken into account to determine site viability. Moreover, the authors suggest that government incentives and electricity prices have to be considered in the feasability study. This is in line with Keivanpour et al. (2017) outlining a full overview of factors to consider in a feasability study. This include geographical and technical measures, technology, economics, and government policies. A complete feasibility study provides governments, policy makers and investors with relevant information to make regulatory policies and potential profitable investment decisions. It can also highlight areas of technical and economic improvement, promoting technology enhancements made by developers.

Regarding the economic viability of an OWF, a great number of methods are applied in literature. After assessing an initial 599 academic articles between 2010 and 2020 on the topic, Liu et al. (2021) identified nine commonly used methods. Of these, levelized cost of energy (LCOE), life cycle assessment (LFA) as well as Monte Carlo simulation (MCS) appeared most frequently. In general, LCOE, discounted cash flow (DCF) models with net present value (NPV) and internal rate of return (IRR) seems to dominate, with cost benefit, real option theory and MCS as supplementary methods. An isolated DCF model is not suitable due to the non-extendable and irreversible characteristics regarding how investments are treated.

[2] Norges vassdrags- og energidirektorat. Governmental body reporting to the oil and energy department and responsible of managing the water and energy resources of Norway. https://www.nve.no/

Judge et al. (2019) constructed a lifecycle financial analysis model analysing each project stage such as installation, operational expenses (OPEX) and decommissioning. Here, a DCF model is combined with LFA and MCS on each project stage. The major benefit is the use of detailed discrete-event time series in each iteration.

LCOE are commonly referred to as a projects discounted costs divided on the discounted electricity production during the lifetime of an OWF (Johnston et al., 2020). This measure is applied by a great number of agencies, governments and other academic literature such as NVE (2021), IEA (2019) IRENA (2019) and BEIS (2020). Here, there is no need to calculate future annual cash flow, making it simple-to-use in practice and thus applicable for policy makers.

Put simply, a cost benefit is a ratio of discounted costs divided on discounted revenues. A life cycle assessment captures all costs in the full lifespan of an OWF, including environmental impact. According to Liu et al. (2021), the static nature of these models is being coped with by the inclusion of uncertainty captive models such as using real option theory and MCS. Lee (2011) argues that profit from cash comes from the value of future investment opportunities. Real option is suitable when operating in an uncertain environment, which can be especially true in the assessment of wind resources. As several OWF projects have been financed through auction bidding processes, Welisch & Poudineh (2019) examined if contract for difference auctions yield speculative bidding by developers. Viewing auctions as a real option, they argued if developers lower the bidding price below actual break-even costs due to low penalty of future project bail out. Including Monte Carlo Simulation modelling is a good option when input variables have no specific value, but only estimated intervals. Judge et al. (2019) demonstrate how risk assessment is corporated, enabling various uncertain or stochastic input parameters to be considered. Probability density distributions of future cash flow can be obtained, compared to a constant price as assumed in the LCOE method.

Using reliable data is important in any economic feasability model. According to Aldersey-Williams, Broadbent & Strachan (2019), the data that is used in most cost models is derived from public domain sources and industry samples. In addition, developers' own projected estimates are used, further contributing to the uncertainty of input values. IEA and other agencies usually site their own cost databases in addition to their other publications. Pivotal work was conducted by Aldersey-Williams et al. (2019a) followed by Hughes (2020) using public audited accounts to obtain actual project costs. The former applied the derived data to an LCOE model for the 29 available UK OWFs, while the latter perform a statistical regression analysis in addition to using a DCF-model with MCS on two current offshore wind farms.

At present, there is no available literature applying input data from audited accounts on planned offshore wind projects. Hence, we seek to shed light on the profitability of an OWF deployment in Norway by using audited accounts as the major source. This allows us to obtain an undistorted baseline cost level. Furthermore, the inclusion of a Monte Carlo simulation eliminates part of the uncertainty from operating with future estimates. Our thesis is fundamentally based on work with audited accounts by Hughes (2020) and Aldersey-Williams et al. (2019a).

3. Offshore wind

3.1 Historic glance and market today

Historic glance

World's first offshore wind park was deployed 2 km off Denmark's coastline in 1991 (IRENA, 2019). 11 turbines at "Vindeby" totalled 4,95 MW of installed capacity, less than half of what a modern 10 MW can produce stand alone (WindEurope, 2022). An illustration of historic offshore wind capacity additions is shown in figure 3.1 below.

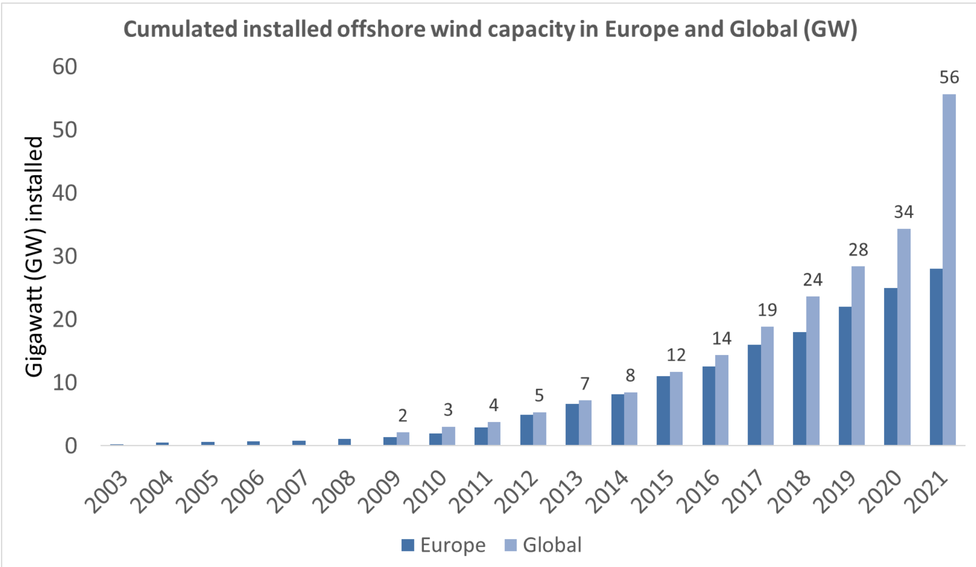

Figure 3.1 *Historic development for offshore wind capacity in Europe and worldwide. Source: Authors own. Numbers obtained from Wind Europe (2022) collected January 24, 2022 from: https://windeurope.org/about-wind/history/ and Statista (2022) collected January 25, 2022 from: https://www.statista.com/statistics/476327/global-capacity-of-offshore-wind-energy/*

In 2010, annual offshore wind capacity additions reached 1 GW, while the same metric was 6 GW in both 2019 and 2020 (IEA, 2021b). Total installed capacity in Europe in 2021 was 28 GW, whilst global numbers accumulated to 56 GW, see figure 3.1. China contributed to half of 2021's capacity additions, while the European Union and the United Kingdom installed the remaining. 2017 marked a key milestone for offshore wind when the world's first floating offshore wind park was commissioned. Hywind Scotland by Equinor unveiled the possibility to go beyond bottom fixed solutions and utilize deeper water and tap into better wind resources. Same year, the first zero subsidy[3] offshore wind auction took place in Germany, reflecting the increasing economic competitiveness of offshore wind. Global installed onshore and offshore wind capacity amounted to 837 GW in 2021 combined, giving offshore wind a share of 6,7%.

Market today

The industry of offshore wind is dominated by few, big market players as illustrated in figure 3.2. High upfront capital costs result in high entrance barriers for new competitors. Few Norwegian companies are represented in the industry, however Equinor stands out with a share of 2%. New entrances such as Aker Offshore Wind and Norseman Wind emerge following the license opening off the Norwegian coast. Most of the companies in the industry develop, own and operate the wind farms, while others such as Macquarie Capital with a market share of 7% is among several investment funds (IEA, 2019). Globally, China has ramped up their investments in offshore wind, as reflected in the global installed capacity for 2021 in figure 3.1.

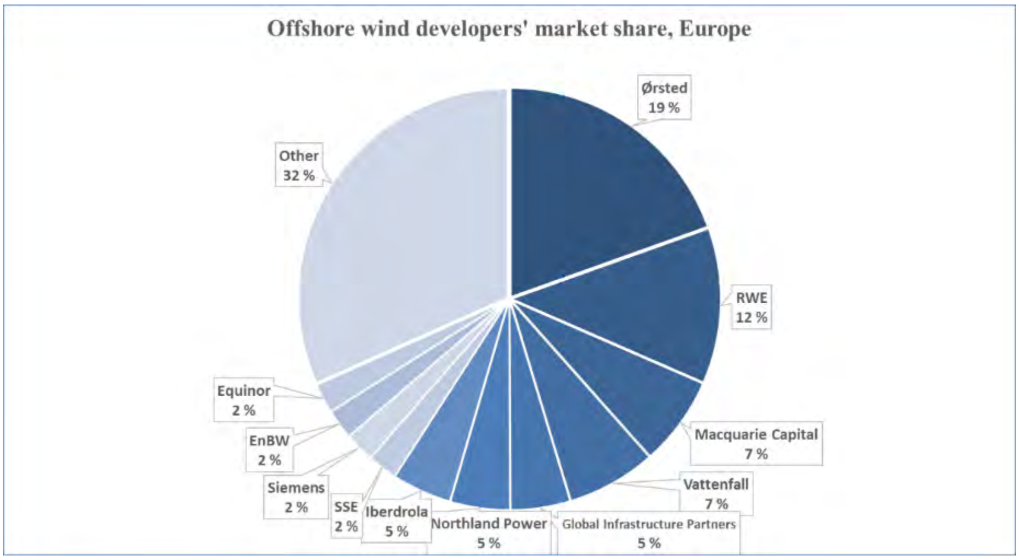

Figure 3.2 *Illustration of market share in Europe for offshore wind developers as of 2020, based on cumulative installations. Ørsted, RWE and Macquarie Capital dominate the market. Source: Authors own. Numbers obtained from Statista (2022), collected may 19, 2022 from* *https://www.statista.com/statistics/804341/cumulative-offshore-wind-installed-capacity-europe/*

[3] In Germany, costs relating to cables and transmission of electricity to onshore grids are borne by the government. Hence, total costs for the developer will be somewhat lower compared to a situation bearing the full capital expenditure.

The amount of turbine manufacturers in the industry reflects the high entrance barriers and capital need. As of 2020, Siemens Gamesa Renewable Energy had a market share of 68% in Europe based on cumulative installations. MHI Vestas follow second with a share of 23,9%, yielding a combined share of over 90%. An overview of total share distribution is illustrated in figure 3.3 below. The lack of industry manufacturers can potentially limit the degree of competition and ultimately hamper cost reductions in turbine costs. Nevertheless, several manufacturers have unfolded as offshore wind deployment emerges outside Europe. In 2018, Chinese-based Envision had a global market share of 15%, materializing on Chinas offshore wind ambitions introducing new turbines to the market.

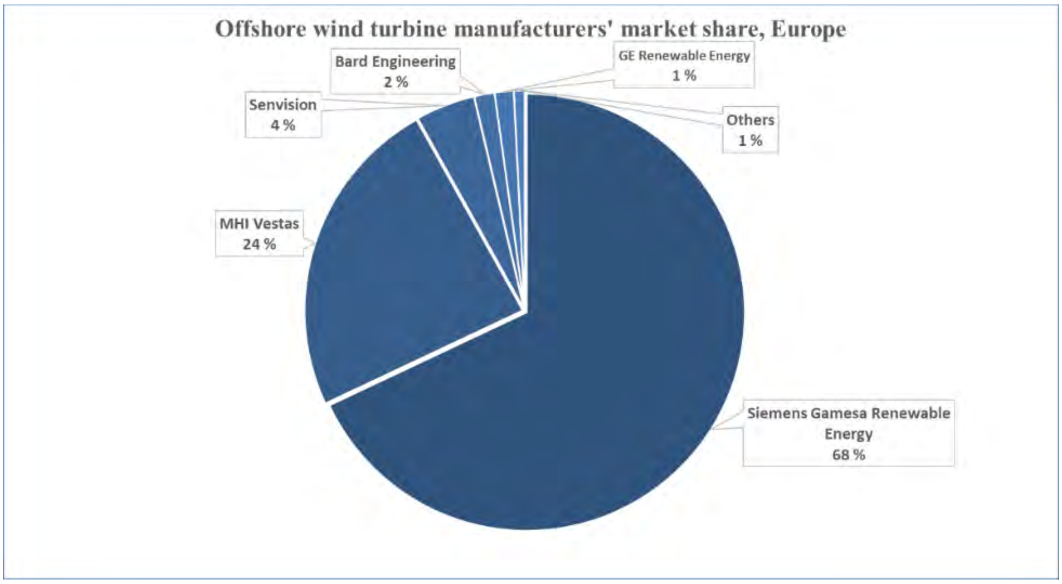

Figure 3.3 *Offshore wind turbine manufacturers' market share in Europe as of 2020. Two market players dominate the industry. Source: Authors own. Numbers obtained from Statista (2022), collected May 19, 2022 from https://www.statista.com/statistics/666579/wind-turbine-manufacturers-eu/*

3.2 Future outlook

Installed offshore wind capacity is set to increase drastically the next decades according to IEA (2019), IRENA (2019) and GWEC (2021). By 2050, global installed offshore wind capacity can be near 1000 GW in the stated policy scenario. This assumes a compound annual growth rate of 11% between 2021-2050 compared to 38,5% between 2000-2018. Looking to 2040, IEA sees annual capacity additions reaching up to 40 GW, while GWEC estimate this number already in 2030. The difference observed across agencies are due to uncertainty regarding whether deployment targets will be met or not. Estimated figures are all dependent on countries delivering on deployment goals set nationally. For instance, the European Union announced in november 2020 its target of deploying 300 GW by 2050 and at least 60 GW by 2030 as part of the EU Green Deal[4]. Figure 3.4 below present the historic installed capacity development in Europe in addition to projections leading up to 2030.

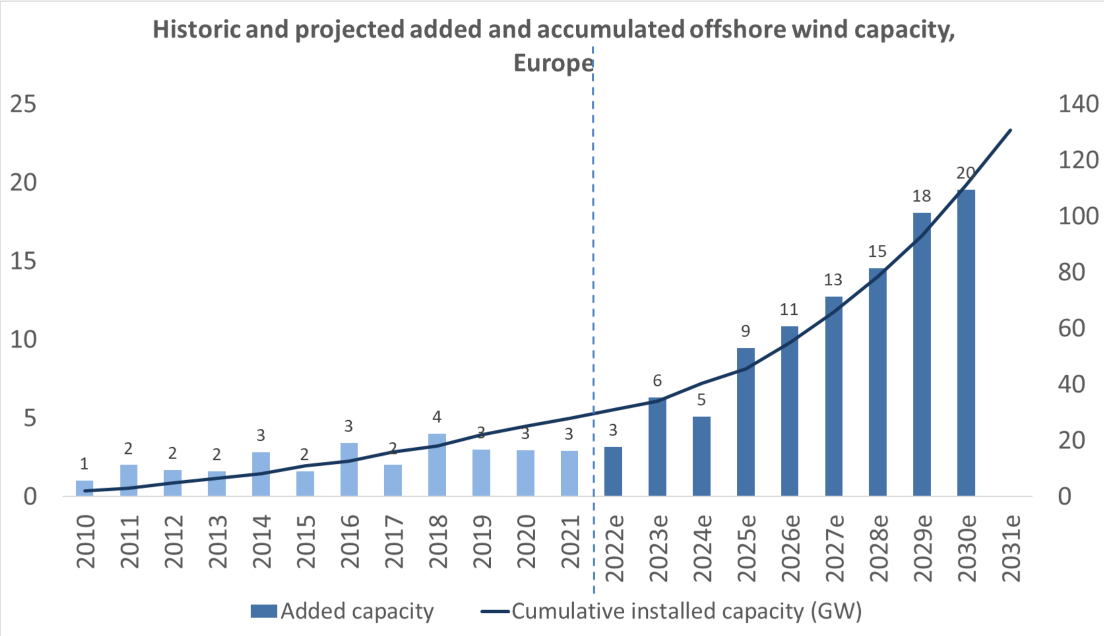

Figure 3.4 *Historic and projected figures of offshore wind capacity. The axis to the right represents total accumulated installed capacity, whilst the left axis present values in capacity additions. Numbers from 2022 is projected. Source: Authors own. Projected values obtained from GWEC (2021), collected may 19, 2022 from* *https://gwec.net/global-offshore-wind-report-2021/*

Leading up to 2030, project pipeline is more spesific, yielding more reliable projections. If projects are to be delivered as planned, a total of 100 GW will be installed between 2022 and 2030 in Europe (GWEC, 2021). As illustrated in figure 3.4, this yield a total of 130 GW installed capacity year end 2030. 74% of this will be build in the second half of this decade. Globally, total installed capacity in the same year are set to be close to 300 GW according to GWEC, and a somewhat more conservative estimate of 228 GW according to IRENA (2019). The former is equivalent to global capacity increase of 223 GW between 2022-2030.

[4] In 2019, the European commission (EC) sat a target of becoming the first climate-neutral continent within 2050. https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

3.3 Wind theory

Wind physics

Wind power is measured by the mass flow through an area as illustrated in equation 3.1 (Letcher, 2017). The wind power (P) is a product of the mass of air (ρ), area of interest (A), and wind speed (U). Assuming mass of air as a constant, the area and wind speed are left as the variables of importance. The area of interest has a positive relationship with wind power, meaning an increased area would yield more power. Furthermore, the equation illustrates that power and wind speed have a nonlinear cubic relationship, where a doubling in wind speed, all else equal, will eightfold the energy power.

(3.1)

$$\boldsymbol{P} = \frac{\mathbf{1}}{\mathbf{2}} * \rho * \mathbf{A} * \mathbf{U}^{\mathbf{3}}$$

P = Power
A = Area (m^2)
ρ = Mass of air (Air density kg/m^3)
U = Wind speed (m/s)

Wind power capture

Not all wind power will be available for utilization. The amount of energy a turbine can generate is defined in equation 3.2 (Letcher, 2017). The equation consists of the mass of air (ρ), the area of interest (A), wind speed (U) and the power coefficient (C_p). The area quantifies each turbine's swept area. The power coefficient compares the rate of power extracted against the total wind power of the wind resource. Thus, the coefficient represents the efficiency of the wind turbine. The theoretical upper limit of the power coefficient of wind turbines is defined by Betz law at approximately 59% (Betz, 1920). As of this limit, it is not possible for a wind turbine to capture more than 59% of the kinetic energy in the wind (Letcher, 2017). New turbines achieve an efficient rate of approximately 50%, which is a high compared to other types of renewable energy (BOW, 2020).

Since the potential for improvement in the power coefficient is marginal, the most effective solution is to increase the swept area. However, increasing rotor blade length will be determined by what is technological and economical possible (BOW, 2020). Furthermore, the cubic relationship with wind speed (U) demonstrates the importance of good wind speed conditions in wind production.

(3.2)

$$C_p = \frac{P_T}{P_{wind}} \Rightarrow P_T = \frac{1}{2} * \rho * A * U^3 * C_p$$

P = Power
P_T = Power extracted
P_{wind} = Total wind power
r = Mass of air (Air density kg/m^3)
A = Area (m^2)
U = Wind speed (m/s)
C_p = Power coefficient

Power curve

Energy output for OWFs vary with wind speeds and wind turbines. The wind turbine will start generating electricity at wind speeds greater than a certain cut-in speed. When wind speed is below the cut-in, there will not be enough wind for the torque to generate electricity. Reaching the rated wind speed for an estimated power curve, the turbine will generate its maximum output of power. To avoid structural damage, the rotor is brought to a standstill at a certain cut-out wind speed (Lydia et al., 2014). Figure 3.5 illustrates a 15 MW power curve.

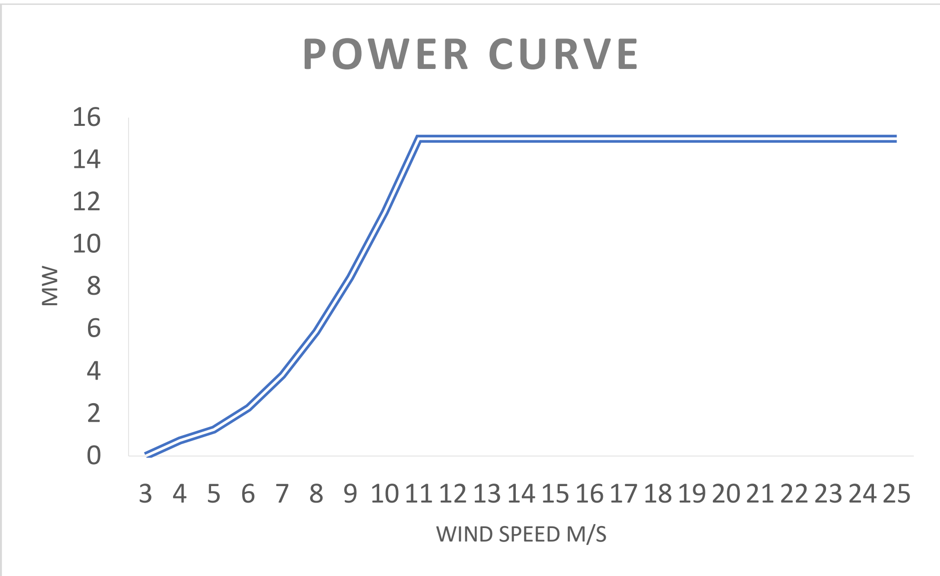

***Figure 3.5** Overview of the power curve for the NREL 15 MW reference turbine. It has a cut-in speed of 4 m/s, reaching the rated speed at 10,6 m/s and a cut-out speed of 25 m/s Source: (NREL, 2020). Graphics: authors own*

Annual electricity production (AEP) and sources of uncertainty for wind farms

In real-world operating conditions power production is usually lower than the theoretical AEP (Letcher, 2017). Losses are usually apparent due to the following factors; (1) The density of air. Higher temperature will decrease the density of air and consequently reduce the net AEP. (2) Turbine availability. Turbines will be unavailable in periods due to breakdowns or scheduled and unscheduled maintenance. (3) Site availability. The electricity grid will experience some downtime because of blackouts or brownouts. (4) Site losses. Some energy losses usually occur when transferring the electricity to the grid. (5) Wake loss. Wind turbines are normally placed in clusters to obtain economies of scale and reduce costs. However, clustering these turbines yield some challenges such as wake loss and turbulence, see figure 3.6 below.

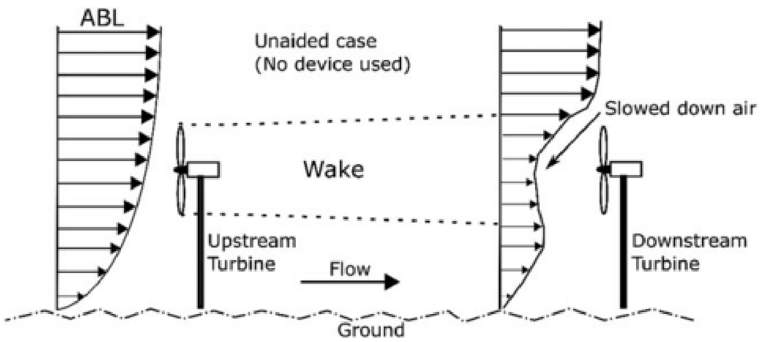

Figure 3.6 *Wake loss illustration. Wind speeds are higher at greater heights. After passing the first OW turbine, wind speed behind the turbine will be lower. Hence, this turbine will have less wind energy to generate power. The rotating turbine blades also creates some turbulence accompanying the wake loss, which increase the need for inspections and repairs, as well as reducing the turbine lifetime. Source: Bader et al. (2018). Improving the efficiency of wind farms via wake manipulation. Wind energy. 21(5).* [10.1002/we.2226](10.1002/we.2226)

Capacity factor

The capacity factor measures the actual amount of energy a wind turbine or wind farm can generate compared to the theoretical maximum generated energy, outlined in equation 3.3. The nominator illustrates actual annual energy production, which is the hourly average production multiplied with number of hours in one year. The denominator describes the theoretical maximum output, multiplying the capacity of a OWF with number of hours in one year. In other words, the denominator describes the OWF going at full capacity for all the hours of the given period. The capacity factor gives the percentage rate of the actual energy produced compared to the theoretical maximum (Letcher, 2017).

(3.3)
$$Capacity\ Factor = \frac{E_{actual}}{E_{ideal}} = \frac{(Time * \overline{P})}{Time * P_N} = \frac{Annual\ Energy\ Production_{actual}}{Time * P_N}$$

$\overline{P}$ = Actual energy production
P_N = Theoretical maximum energy production
Time = Hours in one year (24*365)

3.4 Components of offshore wind farm

A great number of components are necessary when generating, transporting, and serving electricity from turbines offshore to national grid connection onshore. Figure 3.7 illustrates the generic infrastructure needed for a typical offshore wind farm.

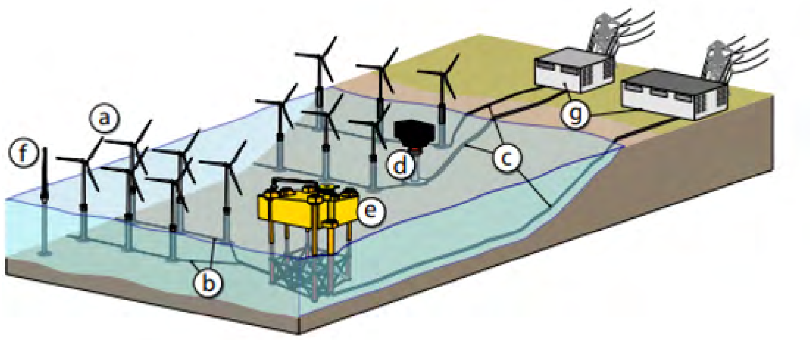

Figure 3.7 Overview of offshore wind farm infrastructure. **(a)** wind turbines; **(b)** array cables; **(c)** export cables; **(d)** transformer station; **(e)** offshore substation converter; **(f)** Meteorological mast; **(g)** onshore substation Source: Rodrigues et al. (2016). A multi-objective optimization framework for offshore wind farm layouts and electric infrastructures. Energies, 9(3), 216

3.4.1 Wind turbine

There are two main offshore wind turbine designs comprising of either a vertical axis wind turbine (VAWT) or horizontal axis wind turbine (HAWT) (Winslow, 2017). HAWTs spin perpendicular to the direction of the wind flow and energy is generated through the full rotation of the blades. VAWTs however are omnidirectional and have blades rotating perpendicular to the ground. Under consistent wind conditions, HAWTs provide in general greater aerodynamic efficiency than VAWT. As a result, these are the preferable choice for OW given that all large-scale wind farms of more than 40 turbines have been deployed with HAWT technology. Focusing on the HAWT, the main components comprise of rotor, nacelle and tower.

Rotor

The rotor primarily consists of three blades, hub casting, spinner and the pitch system (BVG Associates, 2019). The blade size and weight vary depending on turbine type, with a 10 GW turbine having a blade length of 90m and mass of 30-40 tonnes. The biggest blade currently commissioned belongs to General Electric's Haliade-X, with a blade length of 107 meters and a rotor diameter of 220m (GE, 2022). These are connected to the main shaft through the rotor hub made of SG iron. In this hub, blades are bolted on bearings to allow for independent adjustments of pitch angle for each blade. This pitch system help control the power output from the turbine by minimising load, and allow the blades to best capture wind when wind direction changes.

Nacelle

The nacelle houses the electronics which converts the kinetic energy from the wind and rotor into three-phase alternating current (AC) electrical energy (BVG Associates, 2019). For a conventional turbine, the main components within this fiberglass tube is the main bearing, low speed shaft, gearbox, high speed shaft, generator and controller. In addition, a great amount of sensors monitor the turbine by performing health check on key parameters such as rotor speed, output power and pich angle of each blade.

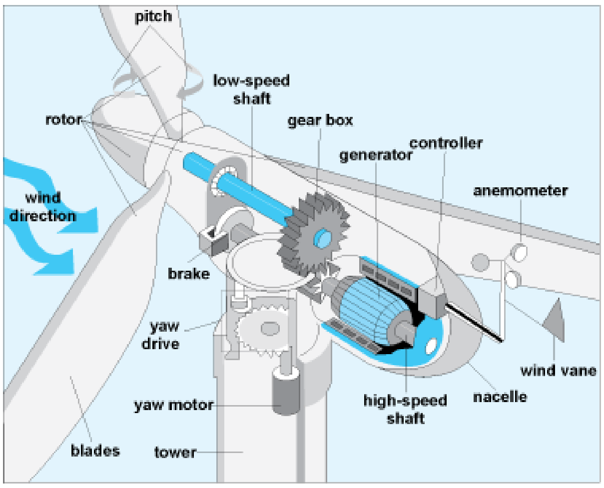

Figure 3.8 *Offshore wind turbine illustration. Supported by the main bearing, the low speed shaft tranfers torque from the rotor to the gearbox. The gearbox connects the two shafts together and increases the rotational speed depending on gearbox type. The high speed shaft drives the generator, in which the convertion from mehanical energy to electricl energy happens. The controller start and stops the turbine to avoid euxhaustion of moving parts when wind speeds are acceptable or to high. Source: Flumerfelt et al. (2020). Wind power. Access Science.* https://doi.org/10.1036/1097-8542.746400

Tower

The tower structure is made of turbular steel, and houses electrical and control equipment. Hub height for a typical turbine of 10 MW is 110m, giving a tower height of 100m and mass of over 600 tonnes (BVG Associates, 2019). The 15 MW NREL reference turbine has a hub height of 150m, giving a distance between blade tip and water surface of 30m (NREL, 2020). Situated on top of the tower, the yaw system rotates the nacelle to face the direction of wind. Wind speed and wind direction data is captured from an anemometer on top of the nacelle and provided to the controller and yaw drive.

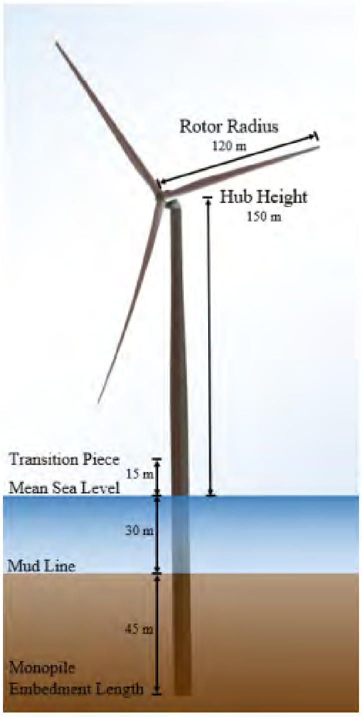

Figure 3.9 *The IEA 15MW reference turbine infographic. Source: Gaertner et al. (2020). Definition of the IEA 15-Megawatt Offshore Reference Wind. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-75698. https://www.nrel.gov/docs/fy20osti/75698.pdf*

Turbine size has increased substantially the last decade and are set to increase further in the future. Between 2010 and 2020, the European average turbine size has more than doubled from 3,1 MW to 7,5 MW (IRENA, 2022). Weighted average hub height increased by 18% from 83m to 98m, while the rotor diameter had a 46% increase from 112 to 163m in 2020. According to IRENA, turbines with a rated capacity of 15MW could be expected by 2030, leaping through 20 MW within 2040 (IRENA, 2019). The German energy company EnBW is already planning a 15 MW turbine from MHI Vestas to be installed in 2025 in the German North sea (Lewis, 2021). Increased rated capacity will likely result in higher CAPEX per turbine, but lower CAPEX per installed MW, due to economies of scale effects. In addition, fewer turbines needed for the same farm capacity can result in fewer maintenance visits, lowering operating costs as well. The objective is primarily to increase the energy output, and the cost trade-off between increased power rating with larger turbines and increased capital costs must be balanced.

3.4.2 Foundation

Turbine foundation

The turbine foundation supports the turbine by transferring the load from tower to the seabed (BVG Associates, 2019). There is a variety of different foundation types regarding size, design and materials. Divided in two main foundation types there are fixed and floating with the former being the dominant technology leading up to today. These foundations accounts for approximately 16% of total capex costs, making it a significant cost element for developers (Johnston et al., 2020).

Gravity based, bucket and monopiles are the preferred technologies among fixed foundations in shallow water up to 30m. As projects move further from shore with greater depths, other foundation technologies are being used. For water depths between 30-70m tripod, triple, twisted jacket and jacket foundation is the relevant options (Sánchez et al., 2019). Jackets are space-framed structures made of steel. At depths greater than 30m, these are preferred over monopiles because they required less steel and have lower weight (Xiaoni & al., 2019). Jackets are currently being installed in the 1075 MW Seagreen project 27km off the coast of Scotland with depths ranging from 40-60m (SSE Renewables, n.d.).

According to Sánchez et al. (2019), the seabed depth seems to be the primarily determinant for choice of foundation with regards to minimizing capital expenditure. Another factor of relevance is the seabed characteristics (NVE, 2019). Stable seabed conditions are critical for an easier deployment of the foundation, whereas a rocky seabed would make installations more problematic for some types of foundations, including jackets. An illustration of the different foundations are presented below in figure 3.10.

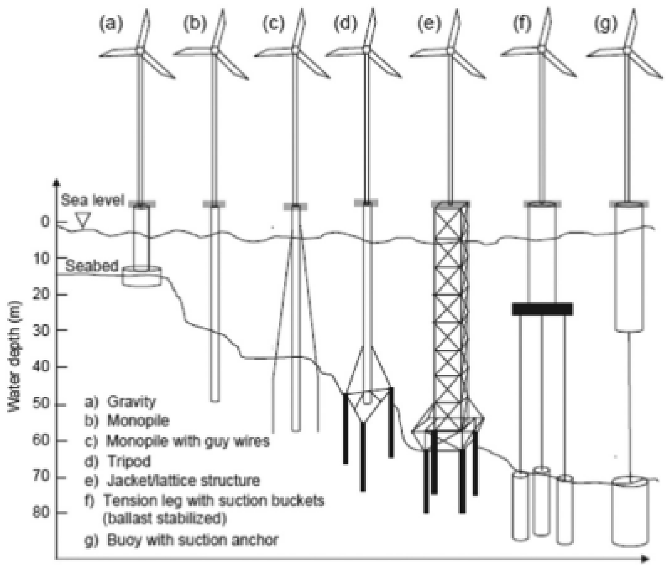

Figure 3.10 *Different foundation types at different seabed depth. Source: Xiaoni et al. (2019), Foundations of offshore wind turbines: A review, Renewable and Sustainable Energy Reviews, Vol. 104, p. 379-393, ISSN 1364-0321,* *https://doi.org/10.1016/j.rser.2019.01.012*

Floating foundation solutions emerge at depths greater than 60-70m, where fixed solutions are no longer economically feasible (IEA, 2019). The main existing concepts are spar-buoy, semi-subersible and tension leg platform, all benefiting from existing floating solutions from the oil and gas industry. These technologies are based on a floating element with mooring system mounted at the seabed with anchors (Xiaoni & al., 2019). Wind speeds are stronger and more stable further from the shore, enabling greater capacity factors (Equinor, n.d.). As many countries have limited coastal areas with depths lower than 50m, floating solutions increase the flexibility regarding choice of optimal location for the wind farm. Although several advantages over bottom fixed solutions at greater depths, overall costs need to be reduced through technological enhancments in order to be competitive in the following years.

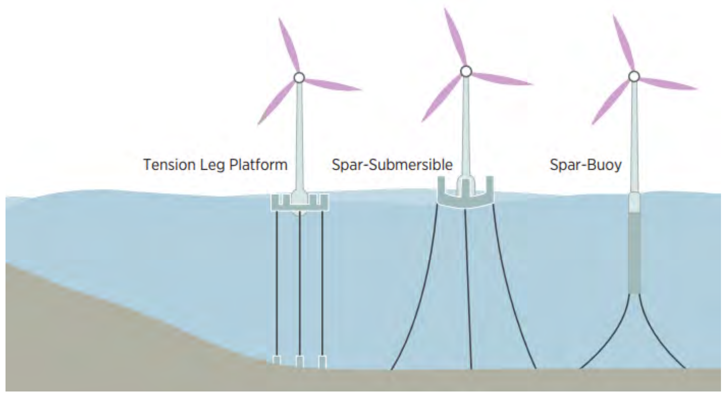

Figure 3.11 *Illustration of the three dominant floating foundation technologies. Source: (IRENA, 2019)*

3.4.3 Electric power transmission

Array Cables

Offshore wind turbines require a connection to a power network to distribute the generated electricity. A cable network consists of array cables and export cables, delivering power from the offshore wind turbine to the onshore grid (BVG Associates, 2019). As project turbine rating increase, fewer turbines are needed for the same farm capacity resulting in less array cables. Nevertheless, bigger turbines need to be placed further away from each other to avoid increased wake loss. As a result, a trade-off between cable costs and wake loss needs to be considered when designing the OWF layout (Baring-Gould, 2014).

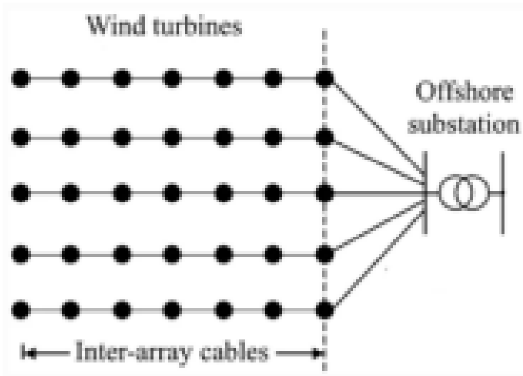

Figure 3.12 *Inter array setup. Array cables connect all wind turbines to the offshore substation. Each turbine has typically 1 km array cables on each side. Source: Rentschler, M. U., et al. (2020). "Parametric study of dynamic inter-array cable systems for floating offshore wind turbines." Marine Systems & Ocean Technology 15(1): 16-25.*

Offshore substation

Offshore substations are used to change the voltage of electricity coming from the inter array cables before exporting to the onshore substation (BVG Associates, 2019). Two technologies are used: High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC). The former transport electricity through AC cables, while the latter need to covert AC to DC at the offshore substation, before converting back to AC at the onshore substation (IEA, 2019). Due to this convention, HVDC cables first become economically preferrable over HVAC at distances greater than 80-100km from shore (BVG Associates, 2019). Dogger Bank wind farm, which is currently under construction and are to be completed in 2026[5], will be the

[5] Consists of three 1,2 GW phases. Dogger Bank A and B is expected to deliver first power in 2023 and 2024, respectively. Dogger Bank C is set to produce in 2026.

first OWF in the UK to utilize HVDC cables (SSE Renewable Energy, n.d.). The 3,6 GW project is situated between 130 - 200km from the shore, heavily relying on cables such as DC to minimize electricity loss.

If Europe are to utilize the vast opportunity of offshore wind at greater depths further from shore, the need for interconnectors between several OWFs arises. Until now, each OWF utilize radial connection to the onshore grid such as the Borwin1 and the planned Dogger Bank project. However, total transmission assets and costs could be reduced by clustering several projects in a “hub-and-spoke” system, connecting multiple countries. The North Sea Wind Power Hub (NSWPH) consortium are developing plans for artificial island hubs in the North Sea (NSWPH, 2021). In this way each OWF does not have to develop a separate offshore substation. In the scope of the consortium, the German transmission operator TenneT are currently working on increasing the export capacity of offshore substation to 2 GW within 2030[6]. This is based on a 525 kV rating complementing bigger OWFs such as the Dutch Ijmuiden ver wind farm zone set for two farms of 2 GW (TenneT, 2020).

Figure 3.13 *Illustration of the North Sea Wind Power Hub. Offshore wind farms are connected to artificial island or larger offshore substations ultimately connected to multiple countries through HVDC-cables (yellow lines). Production of hydrogen from surplus energy when electricity demand is low could be transported through pipes (blue lines). Source: North Sea Wind Power Hub. Obtained April 11th 2022 from https://northseawindpowerhub.eu/key-players-wind-industry-support-ex-amination-feasability-of-north-sea-wind-power-hub/*

[6] Two offshore grid connections; Net op Zee Ijmuiden Ver Alpha and Net op Zee Ijmuiden Ver Beta. The former to be operational in 2028, and latter within 2030. A third, called Gamma, is announced and could be operational according to https://www.offshorewind.biz/2021/10/26/rvo-talks-6-gw-for-ijmuiden-ver-offshore-wind-zone/

3.4.4 Revenues

The annual revenue obtained from an offshore wind farm depends on net annual energy production (AEP), the market price of electricity and subsidies, see equation 3.4. Increasing one of the components, all else equal, will increase the revenue for the offshore wind farm.

$$\textbf{(3.4)} \qquad \boldsymbol{Revenues = Net\ AEP * \underset{\substack{\uparrow \\ \textbf{Subsidies}}}{Power\ price}}$$

Power price

Power needs to be used at the same time as it is being generated. Consequently, balance between supply and demand is required, called instantaneous balance (Statnett, 2018). To determine the market price equilibrium, power from different sources are gathered at a power market. The Norwegian market is part of the Nordic power exchange called Nord Pool. In Norway, there are five bidding zones (NO1-NO5) that reflect transmission constraints in the Norwegian grid, which can cause different prices in each zone. However, Norway does also have different border-cross capacities with Sweden, Denmark, Netherlands, Germany, and Great Britain (NVE, 2021).

The power price varies with seasonal and weather variations. Usually, the expected balance between supply and demand yield higher prices in the winter and lower in the summer. Cold weather during winter months will increase the demand for electric power (Statkraft, 2022). As the renewable energy share increases, the relationship between weather and prices will increase. For instance, wind power production is dependent on sufficient wind speeds and hydropower must have a satisfactory amount of water in the reservoirs to generate energy (Statkraft, 2022).

About 90% of the generated power in Norway stems from hydropower. Thus, Norway has a large surplus of power when the conditions are favourable for hydropower. The surplus of power is usually exported to other countries (OED, 2021). Since hydropower has the unique property that it can store water in hydro reservoirs, Norwegian hydro producers can reduce production to save water and rather import power from other countries when prices are low (NVE, 2021).

3.4.5 Subsidies

The merchant electricity price exposure is a significant risk factor for a renewable energy project (McKinsey & Company, 2018). Without subsidies, an offshore wind farm would have full exposure to the varying electricity price. Governments can facilitate for offshore wind development by providing different power purchase agreements (PPA) to reduce merchant price risk. For OW, different types of sliding feed-in premiums have been utilized in recent years. One example of a sliding feed-in premium is the Contract for Difference (CfD) which eliminate exposure to the market price **Invalid source specified.**. An illustration of how a two-way CfD works is shown in figure 3.14 below.

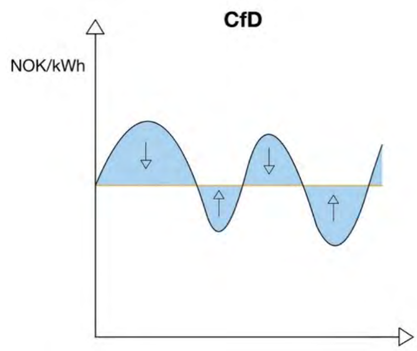

Figure 3.14 *Illustration of a two-way Contract for Difference. When the market price is above the yellow line, the developer must pay the difference to the government. Oppositely, the government must pay the developer the difference when market price is below the predetermined strike price.*
Source: Authors own

Norway and Sweden collaborated to make electricity certificates in 2012. The goal was to make it more profitable to invest in renewable energy production. However, Norway has not announced that it will continue with the certificate schemes (NVE, 2022b).

3.4.6 Auctions

Auctions are becoming increasingly popular for renewable energy development, where offshore wind projects obtained one-third of the total volume auctioned in 2017-2018 (IRENA, 2019). In an auction process, the government acts as the auctioneer and issues a call for tenders from developers of renewable energy. Developers will offer a price per unit of electricity required to realize the project, although not necessarily their break-even price. Based on the bid and other preferred criteria the government evaluates and selects the winner of the auction (IRENA, 2015). The winner of the auction will usually be granted subsidies, for instance a CfD, where the developer's bid equals the strike price of the contract **Invalid source**

specified.. Even if the strike price reflects a great share of project costs, BEIS states that the strike price is not equal to LCOE (BEIS, 2020).

3.5 Cost drivers in offshore wind

The main cost elements for an offshore wind farm are capital expenditure (CAPEX), operational expenditures (OPEX) and decommission expenditure (DECOM) (Bosch et., 2019). Nearly half of the overall costs including financing costs are attributed to CAPEX, reflecting the high upfront investment needed in OWF projects (IEA, 2019). According to BVGAssociates (2022), a typical CAPEX share in the wind farm excluding financing costs amounts to approximately 70%, while the OPEX share is 28%. For non-renewable fossil fuelled energy sources such as natural gas power plants, it can be the other way around with an OPEX share of 40-70% (EWEA, 2009). Compared to onshore wind, offshore wind will by nature have greater costs compared to wind farms deployed onshore. This is reflected through the harsh marine environment, the need for much more costly foundations, more complex logistics as plants move further from shore as well as development costs (IRENA, 2021). A brief overview of the cost breakdown for an OWF are presented in figure 3.15 below. This chapter intends to give a brief description of the different cost drivers.

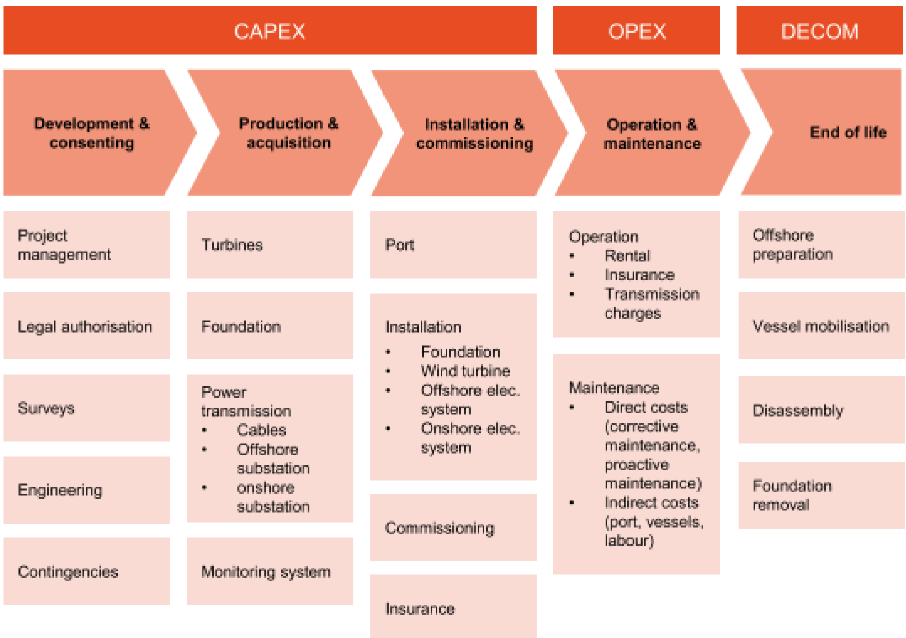

Figure 3.15 *Overview of main cost components in a life cycle of OWF. Source: Bosch, J., et al. (2019). "Global levelized cost of electricity from offshore wind." Energy 189: 116357*

3.5.1 CAPEX

As illustrated in figure 3.15, CAPEX can be divided into several components related to development, production, and installation. CAPEX numbers are usually referred to per MW installed capacity and can be derived from the equation used by (Bosch et al., 2019);

$$\textbf{(3.5)} \qquad CAPEX_i\left(\frac{1}{MW}\right) = C_{dev_i} + C_{turb_i} + C_{found_i}(d) + C_{trans_i}(D) + C_{inst_i}(D) + C_{decom_i}$$

Where development costs C_{dev_i} and turbine costs C_{turb_i} are primarily driven by total installed capacity per grid square (i). The major driver of foundation costs C_{found_i} is depth (d) given the different types of technologies used at different depths. Both transmission costs C_{trans_i} and installation costs C_{inst_i} are dependent on distance (D) from grid square centre to nearest grid point onshore. Finally, decommission costs are usually included as a proportion of installation costs by the developer since it is the reverse order of the installation phase. The relative share of each component will depend on factors such as site conditions (depth, distance to shore and seabed characteristics), supply chain evolution and technology development (BVG Associates, 2022).

Turbine

The major CAPEX cost driver for an offshore wind farm are the turbines as these structures inevitably are the most important component of an OWF. According to BVG associates (2019), turbine costs have a share of 42,2% for a typical project to be commissioned in 2022. This is consistent compared to other literature, as Johnston et al. (2020) presents a share of 39%, while the International Energy Agency state 30-40% (IEA, 2019). When turbine size increases, Meissner (2021) argue that turbine CAPEX will grow more than overall CAPEX decrease due to the square cube law[7]. To cope with this, equipment suppliers are urged to use

[7] Referred to as when an object gets bigger, the volume increases more significant than the surface area. Consequently, more than a linear increase in material is needed as the object grows (given the same material density).

more resilient and lighter materials for the turbine blades and nacelle such as carbon fibre and glass (IEA, 2019).

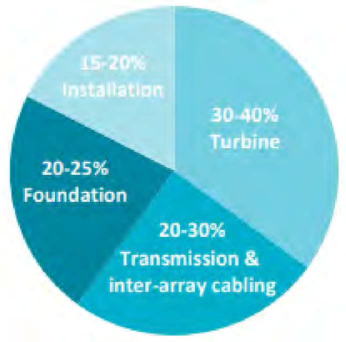

Figure 3.16 *Share distribution of CAPEX drivers. Source: (IEA, 2019)*

The broad literature suggests that an increase in total farm capacity ultimately will reduce total CAPEX/MW due to economies of scale (IEA, 2019;IRENA, 2019). According to results from Vieira et al. (2019), this could be true for farm size of 800 MW or greater. However, few projects greater than this size are currently commissioned, and data relies on estimates rather than actual numbers. As a result, CAPEX/MW might follow a linear trend if the realised cost data are greater, thus reducing the impact of economies of scale. On the contrary, turbine upsizing reduces total number of turbines needed per MW and less inter-array cabling. This could lower installation and operation and maintenance (O&M) costs.

Transmission costs

The second biggest CAPEX driver is transmission costs, including array cabling and offshore substation. According to IEA (2019) these costs typically account for 20-30% of total CAPEX costs depending on distance to shore and regional regulations regarding grid connection. Both BVG Associates and Rystad Energy estimate a CAPEX proportion of 14%, seeing little to no increase in this share leading up to 2030[8] (Rystad Energy, 2021). However, according to IEA (2019), transmission costs' share of CAPEX will increase as total OWF CAPEX decrease the next decades. Global upfront capital costs excluding transmission cost are set to decrease from a 2018 level of \$3 300/kW to \$1 500/kW in 2030 and a further drop to \$1 000/kW in 2040. In this scenario, transmission costs will obtain over half a share of overall farm costs.

[8] This is based on an assumption that bigger turbines will lower inter-array cable costs and offset the increased HVDC and HVAC cable costs associated with projects moving further from shore.

An important and often understated driver of OWF CAPEX is the different approaches to transmission assets. The development and ownership of transmission costs is subject to different models across Europe; the transmission system operator (TSO), government or project developer (IEA, 2019). Current policy in the UK is based on owner-licenses granted by competitive auctions. The developer is in charge of the building of transmission assets before it is transferred to the TSO or offshore transmission owner (OFTO). In Germany, France, Netherlands and Denmark, the TSO build and operate the transmission assets, resulting in lower project costs for the developer. Consequently, the total project CAPEX is highly dependent on the transmission asset policy, affecting the reported numbers by OWF-developers.

Foundation

Marginally behind transmission costs is the turbine foundation. Here, site conditions such as water depth and seabed characteristics significantly affect the costs due to foundation complexity (BVGAssociates, 2022; IEA, 2019). Deeper water require more expensive foundations, and easier ground conditions such as dense sand or stiff clay yield cost benefits compared to a rocky sea bed. The foundation costs typically consitute between 20-25% of total CAPEX, depending on the abovementioned cost determinants. However, technological innovations have expanded the depth scope of bottom fixed structures, enabling development at 55-60m for monopiles and somewhat deeper for jackets (IEA, 2019).

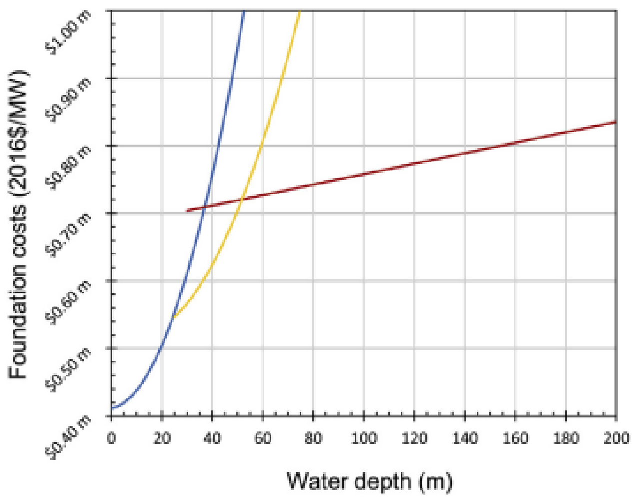

Figure 3.17 *Costs per MW for three different foundation types at different water depths using an 8 MW OW turbine. Monopile (blue), floating TBL (red) and jacket (yellow). Going beyond 55m depth, floating solutions might be more economic feasible than bottom fixed foundations. Source: Bosch et al. (2019), «Global levelized cost of electricity from offshore wind", Energy, vol. 189, 116357,collected from* [*https://doi.org/10.1016/j.energy.2019.116357*](https://doi.org/10.1016/j.energy.2019.116357)

Installation and commissioning

The fourth most important cost driver is installation and commissioning of the wind farm. This usually constitute about 15-20% of total CAPEX according to IEA (2019), while BVG Associates (2022) estimate as much as 27%. These costs include installation of cables, substations and turbine in addition to developers' insurance. To manage this, different specialized vessels are utilized with accompanying day rates (Thema Consulting, 2020). One of the main cost drivers is weather downtime. According to BVG Associates (2019), one third of installation time is lost due to waiting on better weather conditions. This issue is increasingly relevant as projects move further from shore with harsher weather conditions. The increase in turbine size will push day-rates as bigger vessels are needed and installation work gets more complex.

Developers seek to push boundaries regarding operating range of vessels and make innovations to reduce installation time (IRENA, 2016). This include using larger jack-up vessels to carry additional components, pre-construct parts onshore and use yoke or crane hooks to better stabilize components. Construction delivery in MW/year/project has increased from 100-200 to 200-300 MW per year, potentially reducing installation time from more than two years to less than 18 months (IRENA, 2022).

Development and project management

A rather small, but important cost driver is development and project management prior to OWF installation, typically making up 5% of total CAPEX (BVG Associates, 2022). This phase includes activities prior to financial close of the project. Development and consenting services, environmental research, consultancy and engineering are among these. To examine the seabed characteristics, developers perform extensive geological and geotechnical assessments, primarily outsourced to consultants or specialized firms.

3.5.2 OPEX

Another significant element affecting total offshore wind farm costs is the operating expenses (OPEX). After the initial investment, operation and maintenance (O&M) of the OWF is the main cost contributor, typically accounting for 20-28% of total costs (BVGAssociates, 2022; Zhengru et al., 2021). Compared to onshore wind, this share is approximately 5 %. Offshore wind OPEX costs vary depending on factors such as day-rates on vessels, port costs and cost of labour. Distance to shore and project site characteristics also contribute to greater costs than onshore (Bosch et al., 2019). Managing and reducing these costs is therefore effective in reducing the overall project costs.

Operational support

Operational support comprises all activities associated with the operation of an OWF constituting a third of total OPEX (BVG Associates, 2022). This includes training, onshore and offshore logistics, health and safety inspections as well as administration related to compensation payments, insurance and environmental surveys. Remote monitoring is usually enabled through a Supervisory Control and Data Acquisition system (SCADA) as to time preventative maintenance.

Maintenance and service

Maintenance activities ensure the integrity of turbines, foundations and cables. This includes reactive and proactive operations associated with unplanned and planned activities in response to failures (BVG Associates, 2022). This can involve inspections or replacement of failures on components and constitute of two thirds of total OPEX. The cost is associated with equipment, with a direct cost of maintenance effect, and loss of revenue due to lack of maintenance (Zhengru et al., 2021). These costs are therefore heavily reliant on the downtime of the OWF. Distance to shore as well as variability in weather conditions reduces the accessibility of the maintenance fleet and increases the downtime. As a result, maintenance might be postponed if wind speeds are above safe work-levels, and wave heights make turbine service more demanding. Additional OPEX costs are driven by a higher failure rate of OWF turbine components due to the harsh offshore environment compared to onshore. As turbines get bigger, these require larger and more customized vessels in order to complete maintenance work.

To cope with these challenges, developers seek to utilize digital enhancements such as drones and sensors at site (IEA, 2019). In this way a more proactive O&M strategy would be possible, identifying faults in cables, structures, and turbine components at an earlier stage. According to Crabtree et al. (2015), unscheduled maintenance can account for up to 70% of O&M costs. Knowing this, sensors discovering early abnormalities in assets will promote proactive response, and costs due to long downtime can be avoided. Maintenance costs can be reduced by 30-40% with a shift from corrective to predictive strategy supported by the use of digital twins[9] and sensor systems (North Wind, 2022). In additions, drones can reduce the need for physical inspections demanding human labour and expensive vessels on high day rates. Visual inspections can be done remote, thus reducing costs.

3.5.3 DECOM

At the end of an OWFs operational life there are several options to consider relating to end-of-life strategies. This include extending the operational life through component replacement and risk analysis, repowering the site with new turbines and foundation or a full decommissioning (BVG Associates, 2019). The latter involves returning the site to its original state, removing all components. So far, only a few wind farms have been decommissioned, hence methods and cost estimates vary. According to Bosch et al. (2019), decommissioning costs can be between 1,2-3% of full life cycle costs. However, developers usually include DECOM in installation costs, typically with a share of 60-70%. In general, a complete decommissioning of an offshore wind farm can constitute up to 14% of CAPEX cost (BVG Associates, 2022). This is gross numbers and exclude any residual value of components. Currently, tower and nacelle components are highly recyclable with a rate of over 95% (Engie, 2021). Revenue from these can be obtained, minimizing the net decommissioning cost. Today, composite materials in blades and nacelle cover are non-recyclable, but current engineering is working on a 100% recyclable blade, increasing the residual value of an OWF.

3.5.4 Cost of financing

Weighted Average Cost of Capital (WACC)

To determine the correct market value of a project, the investors need to discount the project cash flow with an appropriate discount factor. By assuming that investors are risk-averse, they need to be compensated for funding risky projects. The risk can be translated into a cost of capital measure called weighted average cost of capital (WACC). This is commonly used in renewable energy projects (Tagliapietra et al., 2019). WACC after tax can be written as in equation 3.6 below.

[9] Recognized as a real time digital version of a physical object, for instance the gearbox component in a wind turbine.

$$WACC = \frac{D}{D+E} * R_d * (1-t) + \frac{E}{D+E} * R_e \quad (3.6)$$

$$R_e = r_f + \beta_e(r_m - r_f) \quad (3.7)$$

$$R_d = r_f + Risk\ premium \quad (3.8)$$

WACC = Weighted Average Cost of capital
D = Debt
E = Equity
R_d = Cost of debt
R_e = Cost of equity
r_f = Risk free rate
β_e = Systematic risk on equity
r_m = Risk premium of the market
t = Nominal Tax rate

WACC reflects the capital structure of financing as well as the cost of debt and equity. The cost of debt (R_d) reflects a risk-free rate (r_f) along with a project-specific premium, shown in (8). Cost of equity (R_e) is given by the Capital Asset Pricing Model (CAPM) in (7). The CAPM reflects a risk-free rate (r_f) in addition to a risk premium of the project. The risk premium for the project is obtained by weighting the market premium (r_m – r_f) with the relative risk of the project (β_e) (Plenborg & Kinserdal, 2021).

Financing structure

Financing an OWF requires high upfront capital investment. A traditional method of financing fossil-based power projects is by corporate finance, where debt and equity are raised at company level. An increasing share of renewable energy financing has been done through project finance. Here, the project raises debt and equity for the self-contained legal entity called a special purpose vehicle (SPV). The debt and equity investors are only paid through the cash flow from the project. In case of default, the debt providers will only recourse to the project assets, which entails that the debt providers cannot recourse to any other asset at the company level (Steffen, 2020). In a study of the costs of financing offshore wind, PWC found that the spread between LIBOR[10] and offshore wind projects has decreased **Invalid source specified.**. PWC emphasize that with an increasing share of financing with project finance, banks must be more familiar with the specific project because of the non-recourse debt. This could be one of the reasons for a lower cost of capital.

Risk during development and operations

Since the risk-free rate does not vary significantly, the risk premium is of interest when comparing different OFW projects (Steffen, 2020). An offshore wind project will be exposed to different kind of risk during project development and operations. OWF requires preparations and development that could end in significant sunk costs if the project does not proceed (Arup, 2018). PWC emphasize that different phases in the offshore wind lifecycle have different levels of risk. The risk peak during the development phase which includes site selection and research, as well as contracting and financing. In the phase of construction, the risk decreases before reaching its lowest in the operation phase (PWC, 2020).

3.5.5 Learning curve

The learning curve, identifying cost reductions due to increased experience in a manufacturing plant, origins back to 1936 and the airplane industry. Today the learning rate represent the cost decrease observed for each doubling of installed capacity (Williams et al., 2017). Solar PV has experienced a rate of 34% between 2010-2020 in effect of great cost reductions associated with high global deployment (IEA, 2019). For offshore wind, calculating a learning curve can give valuable insight in what to expect for future cost reductions. Here, IEA assume a learning rate of 15% supported by the projected OWF deployment the next decades. Industry learning about development and more efficient supply chains will possibly aid equipment manufacturers bring bigger and more efficient components to the market. However, Williams et al. (2017) stress that there exists few publications on offshore wind learning rates. Conducting a meta analysis, they observed estimates ranging from -3 to 33% in the literature. In addition, they developed a global adoption model with additional variables affecting the learning rate such as energy, wind quality and exogenous capital fluctuations. With this they

[10] Reference rate for the risk-free rate in the market. The average interest rate of loan offered between banks in the US interbank market (Norges Bank, 2019).

obtained a learning rate between 7,7 and 11% with a preferred estimate of 9,8%[11]. Voormolen et al. (2015) also note that it is challenging to account for differences in geographical characteristics for each offshore wind project when estimating learning curves as opposed to solar PV. Hence, care should be taken when utilizing cost projections derived by learning curves.

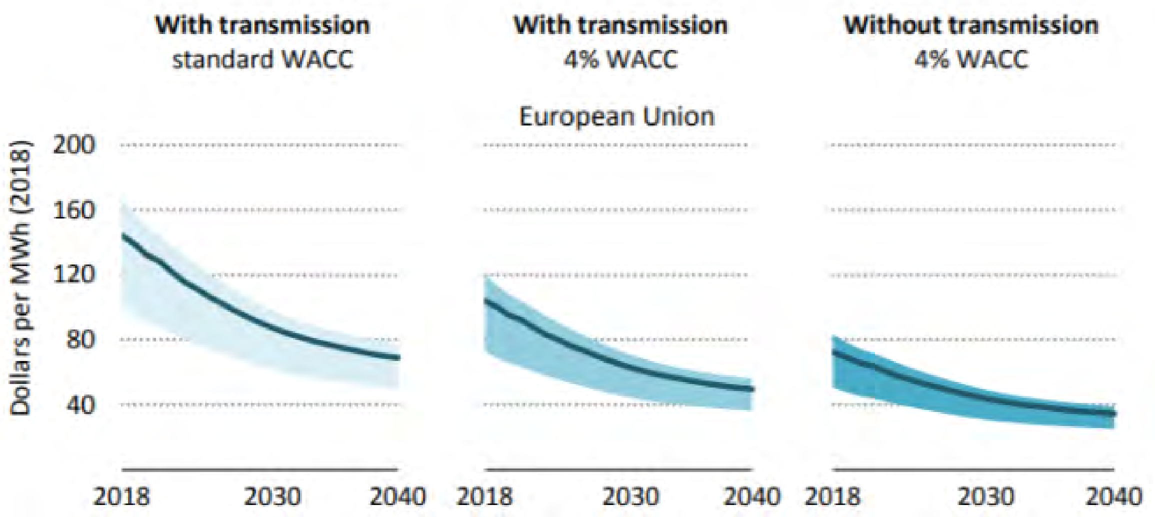

Figure 3.18. *Illustrated learning curve between 2018 and 2040 with and without transmission costs and applying a WACC of 8% and 4%. In line with global deployment goals, LCOE will decrease 15% each time total installed capacity doubles. Source: IEA, 2019, p.43*

[11] Cost data are derived from 789 global onshore and offshore projects from 1982-2015, with most projects being commissioned after 1998.

4. Data

In this chapter, data sources to be used in further cost analysis of Sørlige Nordsjø II (SN II) are presented and explained. The main revenue and cost components for an offshore wind farm is included, hereby revenues, WACC, CAPEX, OPEX and DECOM in addition to plant lifetime. To review the broad scope of current literature, cost data are drawn from a variety of sources. This includes historic audited accounts, academic literature, energy agencies as well as public domain sources. Additionally, the authors have reached out to developers to get insight in project specific numbers without success. Electricity price data are obtained from Nord Pool, the leading power market trader in Europe.

4.1 Special purpose vehicles

Using reliable data when conducting a cost evaluation is critical (Johnston et al., 2020). However, cost data regarding offshore wind still fluctuate and varies in transparency. Hence, current literature is dominated with cost estimates from public domain sources such as company presentations, press reports and commercial databases (Aldersey-Williams et al., 2019a). A novel approach is emerging using publicly available accounts[12] from special purpose vehicles (SPVs) set up for each offshore wind farm by the developer. Pioneer work was first conducted by Aldersey-Williams and his collegues (2019), followed by Hughes (2020). In brief, a developer creates a SPV to build and operate an offshore wind farm. Thus, this company reports financial data from establishment of the SPV to the end of operating life. In this way it is possible to extract actual project costs. Based on this methodology, a neutral baseline for current costs of building and operating an OWF will be carried out and compared against numbers obtained from public domain sources elsewhere.

[12] Audited accounts from offshore wind Limited companies are available from the UK government at https://find-and-update.company-information.service.gov.uk/ .

4.2 CAPEX costs

4.2.1 Audited accounts

CAPEX numbers can be identified in the financial report for each SPV as "additions to fixed assets". Global and European CAPEX numbers need to be treated carefully due to the differences in how transmission assets are costed. Transmission costs are for instance born by the developer in the UK, but not in countries such as Germany and the Netherlands. As such, accounts numbers used in this thesis are based on farms in the UK. A full description of the methodology used in extracting the CAPEX numbers can be found in the appendix of Hughes (2020). A total number of 38 UK offshore wind farms with readily audited accounts is included in the data set obtained from Professor Gordon Hughes at the University of Edinburgh (Hughes, personal communication, March 20th 2022). Year of commissioning vary between 2000 to 2021 and includes OWFs with installed capacity between 4 and 1218 MW, depth from 5 to 120m[13] and distance to shore ranging from 2 to 120km.

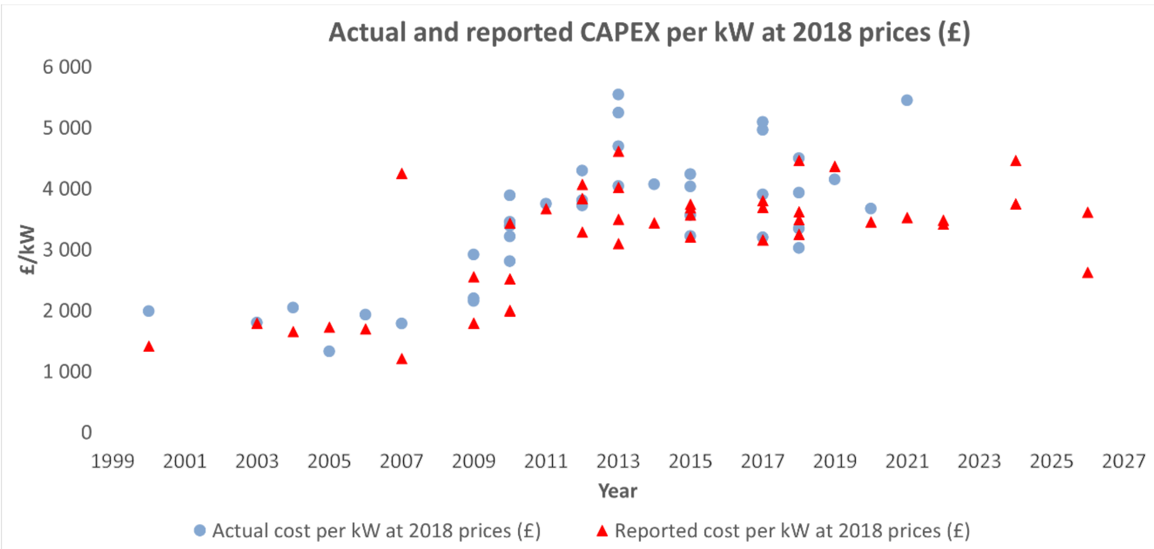

Figure 4.1 *Actual costs (blue) versus reported costs (red) from audited accounts at 2018-prices. Costs were considerably lower from year 2000 to 2010 before increasing around 2009-2010 and has then flatten out the last decade, especially from 2014. Source: (Hughes, personal communication March 20th 2022). Graphics: Authors own*

[13] Hywind Scotland is a 120m deep floating offshore wind farm developed by Equinor in 2017 (named Statoil at that point). The deepest bottom-fixed wind farm in the data set with readily audited accounts is Beatrice offshore wind farm at 45m.

Voormolen et al. (2015) suggests that half of the observed CAPEX increase in Europe is due to increased distance to shore with accompanied greater depths. Increased commodity prices are also presented as a reason for the increase. Knowing that cost of turbine makes up approximately 40% of total OWF CAPEX, fluctuations in steel prices will heavily influence total costs. An additional CAPEX driver Voormolen et al. highlights is the limited competition in the marked, exemplified through Siemens turbine market share of 86,2% in 2014 and 68% in 2020.

Compared to reported numbers from public domain sources and developers own estimates, actual CAPEX costs for the 38 operational UK wind farms are on average 18% higher. This is supported by Aldersey-Williams et al. (2019a), confirming that figures from public domain sources are found to be lower than numbers from audited accounts.

4.2.2 Baseline costs

To obtain a representative baseline cost estimate of current OWF development, some projects need to be removed from the dataset. Limiting year of commissioning to 2015 yield more stable costs per MW regarding trends in distance to shore, depth and installed capacity. In addition, turbine size lower than 3,5MW is excluded to obtain more relevant cost determinants. Table 4.1 summarize the project assumptions used to obtain baseline numbers.

			Sample size: 15
Assumptions	**Min**	**Max**	**Comments**
Year	2015	2020	Projects prior to 2015 excluded
Turbine size (MW)	3,5	8,0	Exclude turbine size <3,5 MW
Dist. To shore (km)			No criteria
Capacity (MW)			No criteria
Depth (m)			No criteria

Table 4.1 *Assumptions made to obtain baseline costs for UK offshore wind farms. Source: Authors own*

Table 4.2 below summaries average, median, standard deviation and confidence interval for a baseline project. The average values yield a CAPEX of £4 095/kW ± 677,72. This is in line with other authors using audited accounts from UK OWFs, showing an average CAPEX of £2000-4000/kW between 2010 and 2020 (Aldersey-Williams et al., 2019). To extrapolate 2015-2020 figures to 2021, this thesis assumes numbers in the lower end using the standard deviation of the estimate. This gives an estimated CAPEX per kW of £3 418 for base year 2021 at 2018 prices.

Values		Average	Median	SD	Confidence interval	
CAPEX	£/kW	4 095	4 073	678	3 418	4 773
OPEX (first year)	£/kw/year	123	106			
OPEX (lifetime)	£/kw/year	117	111			
OPEX 2020	£/kw/year	118	118	25	93	143
Turbine size	MW	6	7			
Distance To shore	km	25	15			
Capacity	MW	310	284			
Depth	m	29	30			
Development year	year	2018	2018			

Table 4.2 *Overview of baseline costs at 2018-prices and project characteristics. This is further referred to as «base project». Source: authors own*

Several additional estimates of historical and current CAPEX cost can be obtained from public domain sources and research papers. The International Energy Agency (IEA) reports a global CAPEX of £3 317/kW[14] in 2018, identical with reports from the International Renewable Energy Agency (IEA, 2019; IRENA, 2019). IEA also reports figures for Europe of £3 048/kW[15], although this excludes transmission costs. A more specific number of £2 370/kW is presented by BVG Associates (2019), using a typical OWF to be commisioned in the UK sea in 2022. This consisits of a hundred 10 MW turbines, 60m off the coast with a depth of 30m. A similar number is presented by NVE, representing costs in 2021 (NVE, 2022a). An email was sent to NVE which provided insight into the model data used (Buvik, personal communication, april 19th, 2022). The model confirming that figures are partly derived from BVG Associates (2019) in addition to data from the National Renewable Energy Laboratory (Stehly et al., 2020). Thus, they obtain a CAPEX figure of £2 590/kW[16].

Before projecting the baseline cost derived from audited accounts to 2030, the price level needs to be adjusted to 2021 prices. Using the British consumer price index[17], this is equivalent to a cost going from £3 418 at 2018 prices to £3 702/kW in 2021 prices.

[14] Originally $4 553/kW
[15] Originally $4 000/kW
[16] Originally NOK 29 737/kW
[17] GBP price multiplier of 1,08318. From: https://www.ons.gov.uk/economy/inflationandpriceindices

4.2.3 Projections

Several cost projections for the upcoming decades have been made by governments and agencies, primarily driven by offshore wind deployment goals. Leading up to 2030, IRENA estimate a global upfront capital expenditure of £1 295-2 439/kW[18] (IRENA, 2019). Estimates heavily rely on enhancements in turbine technology, development of OWFs and O&M activities as well as economies of scales in the supply chain. Fast forward to 2050, CAPEX per kW is expected to drop further down to £1 067-2 134[19] as global installed capacity reach near 1000 MW. This is in line with values presented by IEA, estimating a global CAPEX for 2030 and 2040 of £1 905 and £1 448/kW[20], respectively. To obtain these figures, IEA assume capital cost to decrease 15% each time global capacity doubles (IEA, 2019). Hence, cost reductions rely on OWF deployment goals being met, yielding learning rates to push innovation. China is set to be a major contributor of this, adding 100 GW worth of capacity within 2040. The UK has been a cornerstone in offshore wind farm development, hence future estimates from the UK Department for Business, Energy & Industrial Strategy (BEIS) is of interests. BEIS estimate a UK CAPEX of £1430/kW by 2030 (BEIS, 2020). Hence, increased deployment and learning effects are major drivers of costs reductions in addition to turbine capacity increase. As turbine size increases, BEIS assumes CAPEX per kW to decrease due to economies of scale.

Another approach is used by NVE, gathering projected cost estimates from a variety of sources for floating and bottom fixed OWFs (NVE, 2022a). The cost development leading up to 2030 are shown in a base case, a good case with lower costs and a bad case with less cost reductions. Sources used is JRC[21], NREL, IEA, University of Berkeley and InnoEnergy, forming average estimates before adjusting figures somewhat more neutral. Thus, NVE obtain a base decrease in CAPEX of -15%, a good case of -30% and a bad case of -7% as shown in table 4.3. In numbers, the base case amounts to £2 226/kW[22] in 2030. These cost projections are further

[18] Originally $1 700-3 200/kW
[19] Originally $1 400- 2800/kW
[20] Originally $2 500/kW and $1900/kW
[21] Joint Research Center, a part of the EU Science Hub delivering science and knowledge service. https://ec.europa.eu/info/departments/joint-research-centre_en

[22] Originally NOK 25 555/kW

reflected in good, base and bad scenarios for 2030. Using the base estimate of £3 702/kW at 2021 prices, a CAPEX of £3 147/kW in 2030 was obtained. Good and bad CAPEX scenario are £2 591/kW and £3 443/kW, respectively as shown in table 4.4. A complete literature overview of historic, current and future CAPEX estimates can be found in appendix A1.

Decrease in bottom-fixed OWF CAPEX 2020-2030			
Source	Foundation	Scenario	% decrease
JRC	Monopile	Good	-35 %
JRC	Jacket	Good	-35 %
JRC	Monopile	Bad	-2 %
JRC	Jacket	Bad	-2 %
NREL		Bad	-12 %
NREL		Base	-30 %
NREL		Good	-41 %
IEA		Base	-35 %
University of Berkley		Base	-15 %
InnoEnergy		Base	-20 %
Average good			-38 %
Median good			-38 %
Average base			-25 %
Median Base			-25 %
Average bad			-7 %
Median bad			-7 %
NVE estimates		Good	-30 %
NVE estimates		Base	-15 %
NVE estimates		Bad	-7 %

Table 4.3 *Overview of percentage decrease in total CAPEX estimated in the literature. Source: (NVE, 2022a), Graphics: Authors own*

CAPEX in £/kW **Scenarios**	**2020**	*2018 prices* **2021**	*2021 prices* **2021**	**NVE's estimates**	**2030**
Good (£/kW)	3 418			-30 %	2 591
Base (£/kW)	4 095	3 418	3 702	-15 %	3 147
Bad (£/kW)	4 773			-7 %	3 443

Table 4.4 *CAPEX projections for 2030 shown in a good, base and bad scenario. The lower range of historic average is chosen for 2021. This value is adjusted to 2021 prices, before the three scenarios for 2030 is applied. Source: Authors' own*

4.3 OPEX costs

After OWF construction and installation work is completed, OPEX costs dominate the expenditures in addition to finance costs. Using precise data on OPEX is thus vital as to determine the profitability of continuous operations. However, developers are more reluctant in disclosing OPEX figures compared to CAPEX in public domain sources. This chapter will provide data obtained from audited accounts and public domain sources.

4.3.1 Audited accounts

As for the CAPEX numbers, OPEX figures can be derived from audited accounts. Since 2011 the transmission assets of OWFs is transferred to separate entities called OFTO, responsible for O&M of the tranmsission network (Hughes, 2020). This unbundling of transmission assets makes extracting OPEX figures more demanding. Nevertheless, in practice the OFTO contract out the O&M to the OWF developer, making it possible to obtain total operating costs by examinating both OWF SPV and OFTO SPV. In brief, total OPEX can be derived by adding operating expenses from OFTO SPV and OWF SPV, and then subtracting the OFTO service charge and finance income[23]. As of this, OPEX data obtained from Gordon Hughes includes 36 UK offshore wind farm with operation time from 2005 to 2020 and are presented in table 4.2 below.

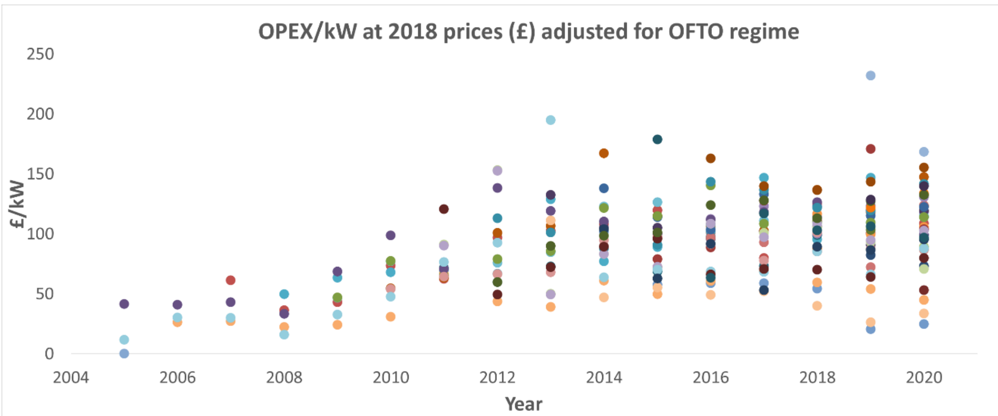

Figure 4.2 *OPEX per kW at 2018 prices adjusted for OFTO. OWF OPEX increased significantly around 2010 before stabilizing leading up to 2020. More sites were developed further from shore, being one of the key driver of increased OPEX costs. Source: Data from Hughes, personal communication, 22nd March 2022. Graphics: Authors own*

[23] A complete description of the OFTO regime in addition to how OPEX values is derived can be found in appendix A1 in (Hughes, 2020)

According to Hughes (2020), operational costs per kW have risen with an annual rate of 5,7% the last two decades after controlling for depth and OFTO effects. However, the major cost increase observed up until 2011 has flatten out and stabilized, thus yielding somewhat lower numbers. In the litterature, some authors indicate that OPEX increase with larger turbines and in later operational years (Wiser et al., 2019). On the contrary, PeakWind (n.d.) using audtited accounts for 47 OWFs suggests that OPEX/kW decrease with lifetime. However, a great caution has to be made for values at greater operational year given the reduced sample size at this age.

4.3.2 Baseline OPEX

To obtain a baseline OPEX cost per kW per year, values representing the most recent cost trends is used. Average first year OPEX/kW is £119,1, whilst average between 2015-2020 is £113,4/kW. A fraction higher is the 2020 average of £118±25,3/kW. Contrary to the CAPEX baseline, the average OPEX value is chosen instead of the lower end in the confidence interval given that 2020 figures are the best estimate to be obtained for current operational expenditures.

Even though OPEX numbers from public domain sources vary, several figures are presented in the literature. IEA (2019) reports a global 2018 number of £68,58/kW/year[24], with China in the lower cost percentile and the US in the upper. IRENA (2021) uses three sources[25] in obtaining an OPEX/kW/year between £53,3 and 98,3 in 2018. The lower range represent established European market and China projects closer to shore. In addition, values depend on the O&M approach used after the original equipment manufacturer warranty period expires. A more specific number is further obtained from BVG Associates (2019), operating with an OPEX/kW/year of £76 for a farm to be commissioned in 2022 in UK waters. NVE (2022a) presents an operating expenditure of £80,4/kW/year[26], primarily based on figures from BVG Associates (2019) and NREL (2020). The baseline OPEX derived from audited accounts is on average greater than the values from public domain sources. Adjusted from 2018 to 2021 prices, increases the base OPEX/kW from £118 to £128,8[27].

[24] Originally 90$/kW
[25] IEA et al., 2018; Ørsted, 2019; Stehly et al., 2018. Stehly study is in upper cost range, Ørsted figures are gathered from a company presentation. Originally $70-129/kW
[26] Originally NOK 923/kW/year
[27] GBP price multiplier of 1,08318 From: https://www.ons.gov.uk/economy/inflationandpriceindices

4.3.3 Projections

Going forward, the OPEX cost trajectory is estimated by several agencies. IEA (2019) estimate values for 2030 and 2040, seing OPEX down to £45,7 and £38,1/kW/year, respectively. Economies of scale and industry synergies with the oil and gas sector are outlined as major cost drivers in addition to technology enhancement and digitalization. Estimates by BEIS (2020) cover the period from 2025 to 2040 with projected capacity factors of 51-63%. Costs for 2025 are assumed to be £54,1/kW/year, before a further drop to £48/kW in 2030 and £45,5 in 2035 using the assumed capacity factor. In 2040, where turbine size of 20 MW is assumed, OPEX are set to reach £44,6/kW/year according to BEIS. A figure somewhat higher than BEIS is presented by NVE (2022a) leading up to 2030. The various sources used in obtaining an OPEX cost of £61,3/kW/year are presented in table 4.6. A complete overview of OPEX costs in the litterature can be found in appendix A1.

Decrease in bottom-fixed OWF OPEX 2020-2030			
Source	Foundation	Scenario	% decrease
JRC	Monopile	Good	-35 %
JRC	Jacket	Good	-35 %
JRC	Monopile	Bad	-2 %
JRC	Jacket	Bad	-2 %
IEA		Base	-33 %
IEA		Bad	-6 %
IEA		Good	-45 %
BVG		Base	-29 %
BVG		Bad	-20 %
BVG		Good	-31 %
Wood Mackenzie		Base	-44 %
Wood Mackenzie		Bad	-40 %
Wood Mackenzie		Good	-50 %
NREL		Bad	-11 %
NREL		Base	-37 %
NREL		Good	-49 %
University of Berkeley		Base	-15 %
Average Good			-42 %
Median Good			-45 %
Average Base			-32 %
Median Base			-33 %
Average Bad			-16 %
Median Bad			-11 %
NVE		Good	-45 %
NVE		Base	-25 %
NVE		Bad	-10 %

Table 4.5 *Overview of projected OPEX decrease estimated in the literature. NVE obtain a 45% decrease in the good scenario, -25% in base, and -10 in bad. Source: (NVE, 2022a), Graphics: authors' own*

OPEX in £/kW/Year Scenarios	2020	*2018 prices* 2021	*2021 prices* 2021	NVE's estimates	2030
Good (£/kW)	92,7			-45 %	70,3
Base (£/kW)	118,0	118,0	127,8	-25 %	95,9
Bad (£/kW)	143,3			-10 %	115,0

Table 4.6 *OPEX projections for 2030 shown in a good, base and bad scenario. Median OPEX cost from audited accounts in 2020 are chosen as base 2021. This value is adjusted to 2021 prices, before three scenarios for 2030 is applied. Source: Authors' own*

4.4 Revenues

4.4.1 Annual electricity output

Wind speed has a substantial impact on the annual energy production recalling its cubic relationship with power, as described in chapter 3.3. Wind speed data in this thesis is provided by Etienne Cheynet from the University of Bergen (Cheynet, personal communication, May 5th, 2022). The data contains spatial average (median) of the mean wind speed and wind direction in SNII. Spatial average gives the average over multiple points, not over time. It ranges from 1992 to 2020 at 150 meter above sea level with hourly resolution. A graphical illustration of the wind speed time series used in this thesis is presented in figure 4.3.

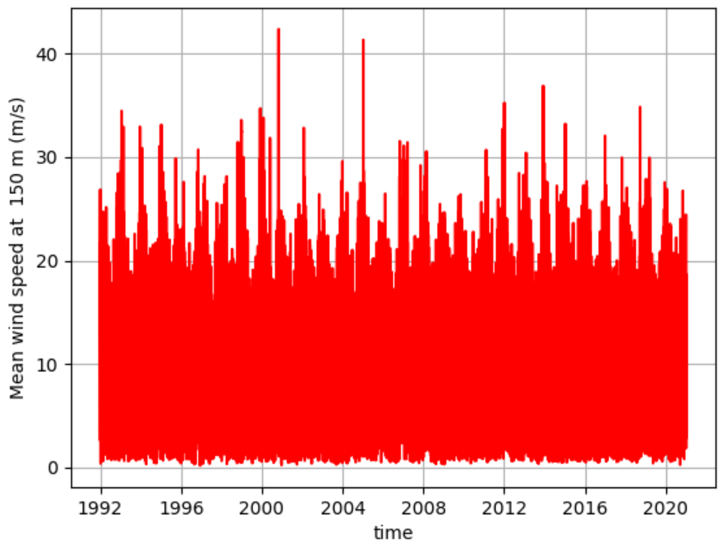

Figure 4.3 Time series of historic spatial mean wind speed (m/s) at 150m hub height for the area SNII with hourly resolution. Source: Cheynet, personal communication, May 5th, 2022

Wind data has been extracted using the programming language Python. Estimation of power output is based on a 15 MW reference wind turbine from NREL, using a power curve from NREL distributed wind Turbine Documentation (NREL, 2020). By interpolating the wind speed for each hour with the Akima interpolation, the energy production is obtained for each hour in the 28 years of data. This yields a capacity factor of approximatly 64%. Furthermore, hourly energy production is aggregated to monthly values. Accordingly, AEP reflects realistic seasonal and yearly variation in wind speeds for the Sørlige Nordsjø II area.

4.4.2 Power prices

Power price data in this thesis are extracted from Nord Pool. Historic monthly day-ahead prices in NOK from the intraday area south of Norway (NO2) was obtained. Since NO2 comprised of both west and south of Norway prior to March 2010, the historic power prices in this thesis ranges from January 2011 to December 2021 (Nord Pool, n.d). To account for inflation, power prices are adjusted to 2021-prices according to values from Statistics Norway[28] (SSB, 2022).

Future power prices

Both Statnett and NVE is expecting higher average power prices in Norway before an expected decrease. According to NVE's analysis they expect a minor growth in average power price in Norway between 2025-2030 due to higher C02-price and increasing power trade between the Nordics and Europe (NVE, 2021). From 2030 to 2040 the average power price is expected to decrease due to a higher renewable share in Europe in addition to wind and solar power development in Norway. NVE presents low, base, and high estimates of the power prices in 2030 and 2040 in NO2. The representative estimates for 2030 are NOK 0,42, 0,54 and 0,70/ kWh. 2040 estimates are NOK 0,38, 0,51, 0,65/kWh.

Statnett is expecting higher average wholesale prices leading up to 2040 and a slightly decrease subsequently (Statnett, 2020). In the base scenario Statnett expects an average price of 35-40 €/MWh in South of Norway after 2030, equivalent to NOK 0,33 – 0,39 NOK/kWh. The increase is a result of increasing C02-prices and more hydrogen production by wind and

[28] Statistisk sentralbyrå. Norway's official statistical bureau. https://www.ssb.no/en

solar production. The slightly decrease after 2040 is a result of technological development of batteries, electrolysis, wind- and solar power resulting in lower cost of development.

4.5 Discount rate (WACC)

Different reports have tried to obtain the cost of capital for the offshore wind industry. Between 2019 and 2020 "Action for Renewable Energy Support II" (AURES II) conducted surveys and in-depth interviews to estimate the cost of equity in EU and the UK. Cost of capital is closely tied to interest rates in each country and project risk, resulting in varying WACC (Aures II, 2021). Nominal, after tax WACC in the UK and EU are estimated to be 3,5-9%. Figures for cost of equity and cost of debt in the report ranges between 5,5-21% and 1,2-5,0% [29], respectively. The Debt ratio lies between 60-80%, with a medium value of 70-75% (Aures II, 2021). On behalf of the Department of Energy and Climate Change (DECC[30]), Nera Economic Consulting conducted an analysis of electricity generation costs and hurdle rates for 2015 and estimates for 2030. Projected hurdle rates for 2030 was 9,3-14,2% with a reference point at 10,4% net of 2% inflation (Nera Economic Consulting, 2015). IRENA has estimated pre-tax, real WACC for offshore wind in the OECD[31] countries to be 5,0% (IRENA, 2021). A comparison of estimates is presented in 4.7 below.

Publisher	Published	Region	WACC (Nominal, after-tax)	WACC (Real, pre-tax)	Adjusted to WACC (Real, after-tax)	Comments
IRENA	2021	OECD + China		5,0%	3,9%	Reflect recent market conditions in 2020
BEIS	2020	UK		6,3%	4,9%	With revenue stabilization (CfD) in 2018
IEA	2021	Not specified		4,0 - 7,0%	3,1% - 5,5%	Depending on region
AURES II	2021	EU + UK	3,5 - 9,0%		1,5% - 6,9%	Based on survey and in-depth interviews in 2019-2020

Table 4.7 *Literature overview of different WACC estimates. A conversion[32] from real pre-tax WACC and nominal after-tax WACC to real after-tax WACC is also presented. Source: (IRENA, 2021), (BEIS, 2020), (IEA, 2021), (Aures II, 2021)*

[29] The risk-free rate (average government bond yields) is subtracted from the risk premium (Aures II, 2021).
[30] DECC was incorporated in the Department for Business, Energy & Industrial Strategy (BEIS) in 2016
[31] Organization for Economic Co-Operation and Development. Consists of 38 countries around the world cooperating to establish common policies across borders to promote sustainable economic growth. https://www.oecd.org/
[32] The following formula is used to convert estimates;
WACC (real, after-tax) = WACC (Real, pre-tax) * tax-rate.
WACC (real, after-tax) = (WACC (Nominal, after-tax) – inflation)/(1+inflation). An inflation rate of 2% and tax-rate of 22% is assumed.

4.6 Project lifetime

Assessing the operating lifetime of the offshore wind farm is crucial in an economic analysis. As of 2021, seven OWFs in Europe has been decommissioned whereas six of them prior to the end of their reported operational life[33] (Shafiee & Adedipe, 2022). Thus, repowering or decommissioning of offshore wind farms will in some cases happen before the technical lifetime of the asset. This could be due to economic gains associated with more modern technology as well as avoiding significant performance loss due to aging of the farm (IRENA, 2019). Current OWFs in operation will ultimately reach their technical lifetime end, and decisions regarding decommissioning or repowering are continuously evaluated. As of 2016, 12% of Europe's OWF fleet crossed the 15-year lifetime, expecting this to reach 28% by 2020 (IRENA, 2019).

Several sources report the range in operational lifetime for offshore wind farms. According to Wiser & Bolinger (2019) conducting a industry survey on onshore wind, developers expected a lifetime of 20 years in early 2000s. By 2015, this increased to 25 years before reaching an anticipated industry average of 29,6 years in 2019, ranging from 25 to 40 years. This is in line with assumptions made by BEIS (2020) using 30 years of operational lifetime for offshore wind. In the same report, onshore wind farms are expected to have a lifetime of 25 years. Compared with assumptions made in 2016, BEIS used 23 and 22 years for the offshore wind CfD project allocation round 2 and 3, respectively (BEIS, 2016). Being commisioned in the years spanning 2021-2025, this works as a benchmark for projects developed these years. However, BVG Associates (2022) assume a lifetime of 27 years for a typical OWF to be commisioned in UK waters in 2022. The broad literature seems to agree upon values in the range of 20-30 years, with the possiblity to extend the lifetime by repowering or replacing key components. Johnston and colleagues (2020) summarizes a project lifetime of 20-25 year for OWFs, reflecting the broad span in literature estimates.

[33] Beatrice, Blyth, Yttre Stengrund, Utgrunden I, Lely and Hooksiel. Worlds first OWF, Vindeby, was decommisioned by Orsted in 2017, being operative in 26 years.

4.7 Generic break even metric – LCOE

Levelized cost of energy (LCOE) is a commonly used measure in determining the economic viability and return on investments of energy generating sources. This metric makes it possible to determine the most important offshore wind cost drivers, serving as a function of total lifecycle costs (Johnston et al., 2020). The relevant model components for an OWF model is shown in figure 4.4. As illustrated, total costs and annual electricity production are the main drivers of LCOE. Reducing capital expenditures through lower price of turbines and foundations ultimately contribute to an lower levelized cost. Likewise, better wind resources will have positiv impact on the annual energy production.

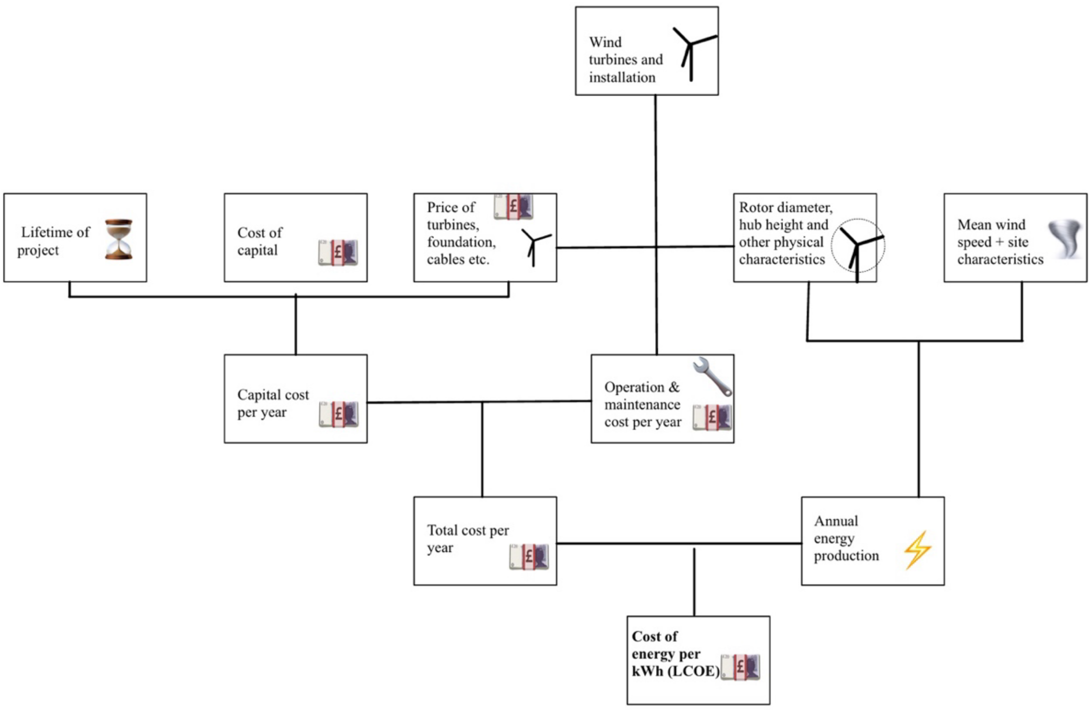

Figure 4.4 *LCOE cost breakdown. Authors' modification from original source paper: EWEA (2009), collected from* *http://www.ewea.org/fileadmin/files/library/publications/reports/Economics_of_Wind_Energy.pdf*

Taking a closer look at current LCOE estimates in the literature, results vary. NVE (2022a) obtain a LCOE for offshore wind in Europe of £60,1/MWh[34] in 2021. For 2030, this decreases to £44,5/MWh using technology enhancements rates. In comparison, utility scale solar photovoltaic (PV) obtained a LCOE of £42,5/MWh[35] in 2021 and is set to nearly half its costs

[34] Originally NOK 0,69/kWh in 2021 and 0,51/kWh in 2030
[35] Originally NOK 0,49/kWh in 2021 and 0,29/kWh in 2030

by 2030 reaching £25,5/MWh. All values are derived using a discount rate of 6%. For reference, IEA (2019) presented historic LCOE figures for 2018 as well as projections leading up to 2030 and 2040. In 2018, offshore wind LCOE was £106,7/MWh[36](76,2) using an 8% discount rate. For 2030 and 2040, IEA estimate a LCOE of £68,6/MWh (45,7) and £45,7/MWh (34,3), respectively. The major driver of cost reductions is set to be improvements in wind turbine and foundation design. Comparing these values with estimations based on UK audited accounts by Aldersey-Williams et al. (2019), figures are somewhat higher. Using actual cost data from 2010 to 2017, they obtained an LCOE for 18 OWFs in the range between £72,1 and 179/MWh. A full overview of LCOE results in the literature can be found in appendix A1.

[36] Originally $140/kWh(100), 90(60), 60(45). Values shown in paratheses are results using a discount rate of 4%, illustrating the impact weighted average cost of capital (WACC) has on levelized costs.

5. Case study - Sørlige Nordsjø II

5.1 Introduction

5.1.1 Norway

Future power demand in Norway is expected to increase due to electrification of industry, transport and households. Additionally, use of industrial power is set to increase, thus rising energy demand likewise. Offshore wind might become a key energy source to meet the expected growth in Norwegian power demand. The growth in power supply is slowing down, and it is expected that the Norwegian power surplus gradually disappear within the next five years (Statnett, 2022). Good wind conditions and a well-positioned Norwegian offshore industry offers great potential for offshore wind power (OED, 2020-2021). Currently, Norway only has one operating offshore wind turbine, a floating demonstration facility outside Karmøy in Rogaland (NVE, 2020). However, a 95 MW floating OWF project set to power two offshore oil and gas platforms is under construction with planned operating start by the third quarter of 2022 (Equnior). Recently, the Norwegian Government announced a major initiative for offshore wind with ambitions of 30 GW installed capacity by 2040 (Norwegian Government, 2022b).

In 2020, the Norwegian Government gave consent to develop offshore wind in two areas, Utsira Nord and Sørlige Nordsjø II (OED, 2020). SNII was recommended by NVE because of the good wind conditions, while the overall negative consequences for the area were few compared to other proposed areas (NVE, 2012). In February 2022, the Norwegian Government announced plans to initiate phase one of SNII. The regulation and framework for how to search for the concession are now being established (Norwegian Government, 2022a). NVE assumes the licensing process will prolong and that development of OW will first start after 2030 (OED, 2020-2021).

5.2 Characteristics

The first phase of SNII involve a 1500 MW development, where power will be transferred to the Norwegian mainland with a radial connection (Norwegian Government, 2022a). Based on technical-economic parameters the Ministry of Petroleum and Energy consider SNII as a suitable location for offshore wind power production (OED, 2020).

Characteristics	Sørlige Nordsjø II		Comments
Area	2691	km^2	
Depth	53-70	m	
Average depth	60	m	
Average wind speed	10,5	m/s	
Distance from shore	140	km	
Distance to connection point	200	km	
Capacity	1500	MW	First part of development phase

Table 5.1 *Sørlige Nordsjø II site characteristics. Source: (NVE, 2012)*

5.2.1 Location

SNII is located east of the big oil and gas fields in the southwestern part of the North Sea and has an area of 2591 km^2. The area is located approximately 140 km from shore and 200 km from the nearest connection point (NVE, 2012).

5.2.2 Depth and seabed conditions

SNII has a depth between 53 to 70m with and average of 60m (NVE, 2012). There has not been conducted much examination of the seabed conditions for SNII, but there are some ongoing research plans (Eide, 2022). The site mainly consists of sand areas but could contain challenging rocky regions. Eide outlines that the seabed is complicated and differ across the area and from other potential OW sites in Norway.

5.2.3 Wind conditions & power prices

SNII has great wind conditions for power production with an average wind speed of 10,5 m/s. Observed extreme values for wind and waves are low compared to other potential OW areas in Norway (NVE, 2012). These beneficial characteristics combined with a large-scale project can offset higher development costs associated with the long distance to shore (NVE, 2012). Bergen Offshore Wind[37] (BOW) has analyzed the wind conditions in SNII, assuming a 15 MW wind turbine and 1600 MW installed capacity. The study indicate that the wind has seasonal variations where production during the winter can be approximately twice as big as during summer. However, stable wind conditions resulted in low variation in production which is preferrable (Greenstat, 2021).

Statnett emphasize that wind production in the SNII area strongly correlates with wind power production in Northern-Europe (Statnett, 2022). Thus, when wind power production in the SNII area is high, the same goes for wind production in the UK. Since the UK have a large share of offshore wind power production, power prices fall when wind conditions are favorable. Consequently, even though power prices observed at trade partners on average is higher, a possible OWF at SNII might not benefit of these. Additionally, Statnett stress that a hybrid connection will be able to take advantage of the short-term price fluctuations at trade partners. These fluctuations are greater than in Norway and considered as socio-economically profitable for a project. However, Greenstat points out that wind resources at the SNII area are less correlated with the UK and Netherlands compared to Denmark and Southwest of Norway (Greenstat, 2021).

5.2.4 Installed capacity

The installed capacity for SNII in this thesis is set to 1400 MW since the power system design failure in the Nordic is 1400 MW. Denoting that if a power loss exceeds the limit of the designed failures, the power system reserves can be inadequate and consumption could be switched off automatically. An increase in the design failures is possible, but would require agreement between the Nordic TSOs and cause large expenses (Statnett, 2022).

5.2.5 Turbine choice

In this thesis the NREL 15 MW reference turbine is chosen (NREL, 2020). Higher rated capacity turbines are expected as to increase electricity production, only limited to what is economically and technologically feasible (BOW, 2020). The industry expects turbines of 15 to 20 MW in 2030 (IRENA, 2019). Hence, a conservative choice of 15 MW is chosen. To

[37] BOW is an initiative at the University of Bergen to strengthen and coordinate education and research. https://www.uib.no/en/bow

support the turbine, a jacket foundation is chosen due to its beneficial characteristics in deeper water.

5.3 Economics of Sørlige Nordsjø II

The following chapter will provide the reader with cost estimates adjusted to the site characteristics of Sørlige Nordsjø II. NVE has made an analysis showing that bottom-fixed OWF development in Norway[38] will be more costly compared to the Europe average using the levelized cost of electricity metric (NVE, 2019). Using the baseline estimates derived from UK audited accounts and other academic literature, an adjustment from CAPEX, OPEX and DECOM baseline project in 2030 will be conducted. This include adjusting for the main OWF cost drivers such as depth, distance to shore, turbine size and installed capacity specific for SNII.

5.3.1 CAPEX

Turbine cost

Total cost of turbine increases approximately by 10% from £1327,8/kW to £1458,2. This is mainly driven by an increase in turbine size going from 6MW to 15MW. According to a press release from Rystad Energy, turbine cost will increase by 54% going from 10 to 14 MW rated capacity (Rystad Energy, 2020). This is equivalent to an increase of 10% per MW. Thus, a turbine cost increase of £130,4/kW was obtained, although this is a cautious estimate. Figures will by all measures be somewhat greater going from our baseline project of 6,3 MW turbine to the 15 MW IEA reference turbine. No further changes in turbine cost specific for Sørlige Nordsjø II is assumed.

Transmission cost

Total transmission costs including cables, offshore and onshore substation increases by 60% from £440,5 to £703/kW driven by increased distance to shore and turbine size compared to the base project. To obtain an estimate more suitable for Sørlige Nordsjø II, reported transmission costs of £791,6/kW from Dogger Bank project C by SSE Renewables and

[38] Sørlige Nordsjø II and Sandskallen-Sørøya nord

Equinor have been used (SSE, 2021). With a distance to shore of 196km, turbine size of 12 MW and total capacity of 1200 MW due in 2026, this project is comparable with SNII. Using a technology enhancement reduction of 10% suggested by NVE (2022a), SNII obtain a transmission cost of £713/kW. In addition, adjustment for the increased turbine size from 12 to 15 MW has been made. According to Shields et al. (2021), going from 12 to 15 MW will reduce array cable cost by 16%[39]. This equivalent to a cost reduction of £9,9/kW assuming array costs account for 11% of total transmission costs (BVG Associates, 2019). The SNII estimate of £703/kW is in line with other figures for SNII done by Statnett (2022) with £725,1/kW[40] and Greenstat (2021) with £499,1/kW[41]. No further adjustments are assumed, although NVE (2019) states that electrical inftrastructure increase with project depth. However, the authors have not succeeded in obtaining any specific cost rates yielding a significant difference.

Foundation

Going from base estimate of £371,3/kW, the Sørlige Nordsjø II specific foundation cost decreases by 15% to £315,6/kW because of increased depth and turbine size. A cost methodology applied by Bosch et al. (2019) is used to estimate the effect of going from 30 to 60m depth on foundation costs. This yields a 43% cost increase and adds £160/kW to get an estimate for SNII. This assumes that the same percentage difference going from 30 to 60m apply in 2030.

Increasing the turbine size from 6,3 to 15 MW will ultimately lower total foundation costs per kW since total installed increases from 310 to 1400 MW. The number of turbines required increases from 49 to 93, increasing total costs by 90% assuming a foundation cost of £3,5 million for a 10 MW turbine (BVG Associates, 2019). However, because of the increased total installed capacity, cost per MW decrease by 58%, lowering total foundation cost by £215/kW.

Installation and commissioning

For the installation and commissioning cost of Sørlige Nordsjø II, a cost decrease of 4,5% from £849,6 to £812/kW was calculated. The negative distance effect is offset by increased

[39] Assumes an OW project with 1000 MW installed capacity
[40] EUR/GBP 0,846
[41] EUR/GBP 0,846. Primarily based on Dogger B
ank project A and B, which have 65km shorter distance to shore (131km) compared to Project C

turbine size effect on array cable, foundation and turbine installation. Installation costs will increase going from 24,6km to 140-200km due to longer distance to cover for the installation vessels as well as more challenging weather conditions. Specific numbers or clear patterns are difficult to obtain in the literature due to lack of developed sites far from shore and in deep waters (Lacal-Aránteguia et al., 2018). Thus, a conservative increase of 10% adding £85/kW to installation costs. On the contrary, increased turbine size will decrease total installation time and costs as there are fewer components to install according to Shields et al. (2021). Array cable installation cost will decrease by 60%, yielding a cost reduction of £15/kW assuming a CAPEX cost share of 3% (BVG Associates, 2019). Secondly, foundation installation cost will decrease by 48% and lower installation costs by another £68/kW assuming a cost share of 17%. Lastly, turbine installation cost will decrease by 60%, assuming appropriate vessels are available in the market. Turbine installation is prone to uncertainty in logistical constraints, especially for 15 and 18 MW turbines which require enough space on the installation vessel. Given this, costs are further reduced by £39/kW assuming 8% of installation costs. In total, going from a 6,3 MW turbine to 15 MW yield a decrease of £122,5/kW.

Development and project management

No development and project management adjustments for Sørlige Nordsjø II are assumed. With this, estimated costs remain at £157,3/kW.

5.3.2 OPEX

Although there are great variation in OPEX estimates in the literature, some adjustments are assumed to be relevant for Sørlige Nordsjø II. OPEX for Sørlige Nordsjø will increase due to greater distance from shore compared to the base project, but is offset by the positive impact of increased turbine size. According to Shields et al. (2021), OPEX costs will decrease by 35% by increasing the turbine size from 6 to 15 MW. This reduces OPEX by £34/kW/year because of decreased vessel demand for fewer turbines. The number of turbine failures per year scales with the number of assets in an OWF, thus reducing total repairs needed. However, as increased turbine size can reduce OPEX costs, increased distance to shore will likely increase OPEX. According to Thema Consulting (2020), distance to shore and local weather are major cost drivers of O&M. Given the location of SNII over 140km off the coast, a conservative cost increase of 20% is applied. In total, the OPEX decrease by 15% from £95,87 to

£81,49/kW/year. This is above figures by NVE (2022a) reporting an OPEX of £61,3/kW/year, although disclaiming great uncertainty in their estimates.

5.3.3 DECOM

The decommission cost for Sørlige Nordsjø II is estimated to be 60% of installation costs, using the lower range of 60-70% suggested by Bosch et al. (2019). This is equivalent to a CAPEX share of 14,1%, which is in line with figures reported by BVG Associates (2019).

5.3.4 Electricity price

Assuming a radial connection to the Norwegian mainland grid only, SNII will not be able to benefit from short-term price fluctuations observed at trade partners such as Denmark, the UK and Germany. These countries have larger short term power price fluctuations than Norway, thus using a hybrid cable across borders could yield a higher socio-economic return for Norway (Statnett, 2022).

5.3.5 Tax

The tax-rate is set to 22% according to the tax-rate applied by the Norwegian Government (Stortingets skattevedtak, 2022, §75).

5.3.6 WACC

In this thesis, project WACC is assumed to remain the same throughout the project lifetime even though, PWC emphasizes that the risk in an offshore wind project vary **Invalid source specified.**. The project is assumed to be financed by project finance with a 75% debt-to-equity ratio. Furthermore, cost of equity and cost of debt in real terms are set to 10 and 3,5%, respectively. This yield a real, after-tax WACC of 4,5%. The cost of capital for a potential site at SNII will depend on the risk associated with the project. Arup empathizes that the cost of capital for an onshore wind farm project often differ from general WACC levels since individual projects includes specific risk that is not reflected in WACC (Arup, 2018). Evidence indicates a difference between project WACC and WACC of 100-200 basis points. Furthermore, if revenues solely rely on the wholesale electricity price, it will result in higher cost of capital in addition to fewer potential investors. Arup found that the WACC can be reduced by 140 to 320 basis points comparing a UK onshore wind project with and without a

CfD. Hence, to reflect the specific risk and no subsidies for SNII project, WACC is adjusted up with 150 basis points to 6%.

5.3.7 Project lifetime

The project lifetime for Sørlige Nordsjø II is set to 25 years, with decommissioning completed in year 26. It can be argued for lifetimes up to 30 years based on industry opinion gathered by Wiser & Bolinger (2019), and assumptions made by NVE for Sørlige Nordsjø II (NVE, 2022a). However, the economic life of the OWF is relient on the long term profitablity, distinguising the technical and economic lifetime of the project. Thus, a prudent assumption of 25 years is choosen for SNII.

6. Methodology

This section consists of a thorough presentation of the models used in this thesis. To evaluate the future profitability of Sørlige Nordsjø II, a DCF model and LCOE are applied. By combining the DCF model with Monte Carlo simulation, the assessment will be more comprehensive in capturing uncertainty in future estimates.

6.1 Discounted cash flow model

The DCF model estimates the net present value for the project as shown in equation 6.1 (Shreives & Wachowicz jr., 2001).

(6.1)

$$\boldsymbol{NPV = \sum_{n=0}^{N} \frac{CF_n}{(1+d)^n}}$$

NPV = Net present value of cash flow
CF = Cashflow in year n
d = Discount rate

The net present value of the discounted cash flows can be interpreted as the attractiveness of investing in the project. Hence, a positive NPV indicate that the project is attractive, oppositely would a negative result indicate the project to be less attractive for an investor. This thesis has not accounted for any socio-economic impacts and should accordingly not be interpreted as a socio-economic result.

To create a more comprehenisve economic assessment, the DCF model is combined with a Monte Carlo simulation running 10 000 - 20 000 simulations. This mathematical tecnique utlilize random sampling and statistical analysis to compute results of uncertain events (Raychaudhuri, 2008). Economic assessments including sensitivity analysis and scenarios is not as suitable as Monte Carlo simulation when combining multiple uncertainties at once (Liu et al., 2021). Instead of calculating one cash flow for the entire project, the model in this thesis run 10 000 – 20 000 stochastic simulations based on historic uncertainty to predict future values. For each simulation, variables are given new random values using normal and beta-PERT distributions. Due to computational limitations, the number of simulations in the thesis are limited to 10 000 – 20 000. However, values do not change significantly going beyond the chosen amount of simulations. Additionally, three future cost scenarios are applied in the thesis instead of simulating cost uncertainty only. Suitable CAPEX and OPEX standard deviations is difficult to obtain. Hence, base, good and bad cost projections are chosen to account for uncertainty in future offshore wind development.

6.1.1 Input variables

The cash flow is calculated yearly and is described in equation 6.2. By defining net revenue as variable OPEX subtracted from the gross revenue, and EBITDA[42] as fixed OPEX subtracted from the net revenue, the equation can be simplified to equation 6.5.

$$\boldsymbol{CF_n = gross\ revenue_n - variable\ OPEX_n - fixed\ OPEX_n - debt\ payments_n - debt\ interest_n - tax_n - equity\ investment_n} \tag{6.2}$$

$$\boldsymbol{Net\ revenue_n = gross\ revenue_n - variable\ OPEX_n} \tag{6.3}$$

$$\boldsymbol{EBITDA_n = net\ revenue_n - fixed\ OPEX_n} \tag{6.4}$$

$$\boldsymbol{CF_n = EBITDA_n - debt\ payments\ \&\ interests_n - tax_n - equity\ investment_n} \tag{6.5}$$

EBITDA

Project EBITDA is estimated by subtracting OPEX from the gross revenue. The gross revenue is a product of the annual energy production and the power price. For each month, the model multiplies a random generated power price with the estimated energy production. Power price forecasting is done by using the riskAMP package, which generates a number according to the beta-PERT distribution (RiskAMP, n.d.). The generated power price will reflect historic seasonal variations, but does not consider effects such as correlation with AEP and production from other energy sources. Energy production is estimated by interpolation in Python. Furthermore, the cumulative energy production for each month in the 28 years of data is summed. As a result, the data provides realistic yearly and monthly variation for the annual energy production. To create different AEP for each simulation, random variability is added. Not doing this would yield the same AEP for all simulations. The element of variation is created by multiplying the standard deviation for the specific month with a random generated

[42] Earnings Before Interests Tax Depreciation and Amortization

number between -1 and 1. Production losses is not taken accounted for. Including this would require a computed wind farm layout, an analytical wake model and would be computationally demanding for the years of historic data used.

OPEX is divided into a variable and fixed part, where the fixed part is 77,5% of the original OPEX value calcuated in chapter 4.3, held constant through the entire project. The variable part of OPEX (VOPEX) is multiplied with AEP. Thus, the VOPEX is estimated per MWh. The VOPEX per MWh is estimated by dividing 27,5% of total OPEX cost by the full load hours. This yields a mean VOPEX/mWh of £4 in the base case, in line with attainable estimates in the literature (BEIS, 2020). Furthermore, the simulated VOPEX for each year is generated according to a normal distribution using riskAMP.

None of the model input variables are inflation adjusted beyond 2021 prices.

Equity investment & debt

CAPEX is represented in the equity investment and debt payments. By assuming a 75% debt rate, the equity investment is calcualted as 25% of CAPEX in year 0 which is the development year. The residual CAPEX investment is reflected in the debt payments starting in operation year 2 onwards. The first two year is considered as a grace period, where the project does not need to pay debt interest or debt repayments. Furhermore, debt interests are calculated by multipling the cost of debt of 3,5% with the remaining debt for the project.

Tax, depreciation & discount rate

For each year the model estimates the possible taxable profit based on the 22% corporate tax rate. Taxable profit is calculated by subtracting debt interest and depreciation from EBITDA. Depreciation is calculated linearily over the depreciation period. By adding up all prior taxable profit, the model only estimate a corporate tax if the deferred tax is less than zero. Lastly, the cash flow is discounted yearly with the discount rate of 6%. An illustration of one simualtion for the base case is presented in appendix A2.

6.1.2 Limitations to DCF with Monte Carlo simulation

DCF models have limited flexibility and would not stand alone be suitable for a long-term offshore wind project with significant uncertainty (Liu et al., 2021). To account for these limitations the DCF model is combined with a Monte Carlo simulation. However, there is no guarantee that the generated random variables obtained in this thesis will follow the distributions assumed the model. Although future power prices are modelled using beta-pert distribution, numbers are based on historic values. These numbers are no guarantee for future prices. Lastly, the applied WACC is constant throughout the lifetime of the project. According to PWC, the actual project WACC would differ with time in a real world scenario **Invalid source specified.**.

6.2 LCOE

The Levelized cost of Energy (LCOE) is the most common way to calculate and discuss the cost of electricity in the energy sector (Johnston et al., 2020). Measuring the discounted cost per unit of electricity generated makes it possible to compare cost of energy across different technologies and projects. LCOE is given by the formula in equation 6.6, where the net present value of total costs is divided by the net present value of the energy production (BEIS, 2020).

$$LCOE = \frac{NPV\ of\ total\ cost}{NPV\ of\ energy\ production} = \frac{\sum_{t=1}^{n} \frac{C_t + O_t + V_t}{(1+d)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+d)^t}} \tag{6.6}$$

C = Capital expenditure (CAPEX)
O = Operational expenditure OPEX)
V = Decommission (DECOM)
E = Expected energy production
d = Discount rate

6.2.1 Limitations to LCOE

Using LCOE to compare cost per unit of electricity generated across different technologies and projects, it is assumed that the measure is comparable. LCOE is often adjusted to meet a particular objective specific for the assessed energy source, thus reducing the comparability with other energy sources (ORI, 2015). Regarding offshore wind, cost assumptions have a large degree of uncertainty due to differing site characteristics and partly immature industry features. Different assumptions in the calculations will have a significant effect on LCOE, further complicating comparison across different OW and other energy projects (Johnston et al., 2020). The recurring OPEX is a significant cost component of an OWF which needs to be costed based on past values and expected future development. Uncertainty in these estimates yield different values of OPEX, which make LCOE less comparable among projects. Furthermore, wind conditions are a vital element when deciding the optimal sites for offshore wind. The differing wind supply will affect the operational efficiency of wind turbines and the resulting varying energy production. However, this is not included in the calculations of LCOE, and rather assumed to be static over the whole project lifetime. Excluding this variable in some models and including elsewhere thus yield divergent LCOE results (Johnston et al., 2020).

Specific for OW, LCOE can vary substantially due to different treatment of OWFs' transmission costs (Johnston et al., 2020). Comparing a LCOE for a UK project including transmission costs with a site in Germany excluding the same costs would yield inefficient comparison. Other reasons further complicating LCOE comparison are that the subsidy and CfD structure often varies between countries. A one-way CfD will influence revenues and ultimately LCOE in a different matter than a two-way CfD Furthermore, LCOE is often expressed in different currencies, meaning currency fluctuations can influence the final value of LCOE (Johnston et al., 2020).

6.3 Internal rate of return

The internal rate of return (IRR) is a financial ratio which measures the return on invested capital (Plenborg & Kinserdal, 2021). IRR is closely related to the NPV, as it gives the required rate of return to obtain a NPV of zero, which is shown in equation 6.7.

$$\textbf{(6.7)} \qquad \boldsymbol{NPV = -CF_0 \sum_{n=1}^{N} \frac{CF_n}{(1+IRR)^n} = 0}$$

Comparing IRR with the project WACC, it tells if an independent project investment should be accepted or rejected. If IRR is higher than the company's WACC the project should be accepted. Conversely, a project with an IRR lower than WACC should be rejected as illustrated below (Yan & Zhang, 2022).

$$\boldsymbol{IRR > WACC \Rightarrow Accept\ project}$$
$$\boldsymbol{IRR < WACC \Rightarrow Reject\ project}$$

7. Results

This chapter present simulated results of the profitability analysis using different scenario values for Sørlige Nordsjø II. Additionally, LCOE was calculated to compare against estimates in the literature.

7.1 Summary of scenario results

A summary of simulation results in addition to LCOE calculations is presented in table 7.1 below. All NPV simulations yielded a negative value, while the good case provided a positive NPV in 16,8% of total simulations.

		Scenarios			
		Bad	**Base**	**Good**	
Mean NPV		-35 484	-18 294	1 381	NOK millions
Standard Deviation		754	825	1 073	NOK millions
Percentile	5%	-37 228	-20 192	-370	NOK millions
Percentile	95%	-33 753	-16 372	3 154	NOK millions
% of cases with PV > 0		0%	0%	90%	
Mean IRR		N.A	-4%	7%	
Required return (WACC)		6%	6%	6%	
LCOE		0,81	0,68	0,55	NOK/kWh
Simulations		10 000	20 000	10 000	

Table 7.1 *Summary of simulation results and LCOE. Source: Authors own*

7.2 Scenario overview

Three different scenarios for Sørlige Nordsjø II was established in accordance with base, good and low estimates derived in chapter 4 and 5. All scenario assumptions are summarized in table 7.2 representing development in 2030. For the base scenario, the project lifetime was assumed to be 25 years, discount rate (WACC) of 6%, and a capacity factor of 64% where the annual full load hours was estimated to be approximately 5600. Production losses such as wake loss and losses to grid was not accounted for. A real market price growth of 2% was further assumed in the base case. The model did not consider the effects of wind correlation between countries or short-term price fluctuations.

In the good scenario, CAPEX, OPEX, decommission and the project lifespan was adjusted. In addition, the number of annual debt payments increased from 20 to 25. CAPEX and OPEX were assumed to have a larger cost reduction due to technology advancement. The decommission cost was assumed to be covered by the revenue from component residual value. Project lifetime was increased by 3 years to 28 years, whereas the market price growth was adjusted from 2 to 3%.

Sørlige Nordsjø II case assumptions		BAD	BASE	GOOD
Installed capacity	(MW)	1400	1400	1400
CAPEX	(NOK/kW)	42 480	39 556	34 074
Fixed OPEX	(NOK/kW/year)	798	678,0	465,3
Mean variable OPEX	(NOK/MWh)	46	45,9	31,5
Project lifetime	(years)	20	25	28
Real discount rate (WACC) after tax	(%)	6	6	6
Corporate tax rate	(%)	22	22	22
Debt-Equity ratio	(%/%)	70/30	70/30	70/30
Debt - grace period	(years)	2	2	2
Debt - no. of annual payments	(years)	15	20	25
Growth in real market price	(%)	1	2	3
Decommission cost (net of residual value)	(NOK/kW)	5593	2797	0

Table 7.2 *Project assumptions for different scenarios. Source: authors own*

		6% WACC			
		Base project	Sørlige Nordsjø II Bottom-fixed jacket		
		2030	2030		
Description	**Project size**	Base	Bad	Base	Good
Average full load hours	**1400**				
Capital expenditures (CAPEX)					
Turbine	NOK/kW	15 243	18 174	16 740	14 050
Transmission costs	NOK/kW	5 057	8 065	8 065	8 065
Foundation	NOK/kW	4 262	4 024	3 623	2 871
Installation and commissioning	NOK/kW	9 752	10 240	9 322	7 601
Development and project management	NOK/kW	1 806	1 976	1 806	1 487
Total capital expenditures (CAPEX)	**NOK/kW**	**36 120**	**42 480**	**39 556**	**34 074**
Net decommissioning cost (DECOM)	**NOK/kW**		**5 593**	**2 797**	**-**

Table 7.3 *Breakdown of CAPEX values in base case 2030 and different scenarios for Sørlige Nordsjø II 2030. Source: Authors own*

Description	Project size	6 % WACC Base project 2030 Base	Sørlige Nordsjø II Bottom-fixed jacket 2030 Bad	 Base	 Good
Operation and Maintance cost (OPEX)					
Fixed O&M	NOK/kW/year	798	838	678	465
Variable O&M	NOK/MWh/year	45,9	56,7	45,9	31,5
Total Operation and Maintance cost (OPEX)	**NOK/kW/year**	**1 101**	**1 156**	**935**	**642**

Table 7.4 *Breakdown of OPEX values in base case 2030 and different scenarios for SNII 2030. The variable O&M rely on full load hours, thus noted in NOK/MWh/year. Assuming 64% capacity factor (5606 hours), variable O&M sums up to NOK 257/kW/year in the base scenario.*
Source: Authors own

7.3 NPV

7.3.1 Base

A total of 20 000 simulations were done in the base case. The capacity factor obtained an average of 64±2%, with the 95% and 5% percentile of 65% and 63%, respectively. The lower range was apparent during the summer when wind speeds were low, and vice versa during the winter. A summary of the resulting NPV and internal rate of return (IRR) in base case is presented in table 7.5 below.

Present value of project (NPV)		Percentile 5%	 95%	
Mean	-18 294	-20 192	-16 372	NOK mill
Std Dev	825			NOK mill
% of cases with PV > 0	0%			
Mean IRR	-4%	-5%	-2%	
Required return (WACC)	6%			

Table 7.5 *Mean value and standard deviation of net present value for SNII. IRR is shown as well. The 95% and 5% cost percentiles were calculated for both NPV and IRR. Source: Authors own*

The NPV for Sørlige Nordsjø II resulted in a mean value of approximately NOK -18,3±0,83 billion. The resulting IRR was -4%, below the required rate of return of 6%. None of the simulations yielded a positive NPV, where the 95% percentile NPV was NOK -16,4 billion as shown in figure 7.1. Figure 7.2 presents a probability distribution of the NPV, showing that the most likely NPV value was NOK -18,5 billion with a 15,2% likeliness of occurring.

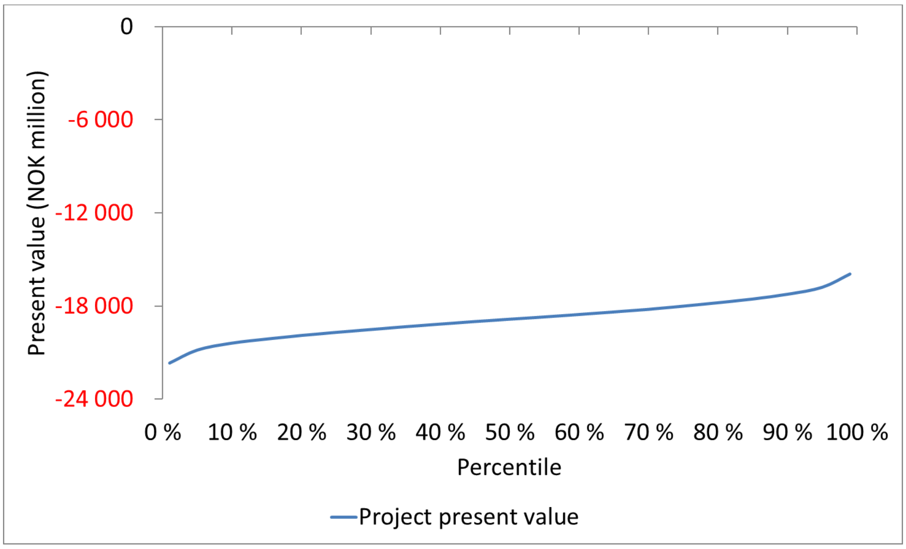

Figure 7.1 *NPV percentile distribution. The best 5% of the simulations yielded a NPV of NOK -16,4 billion or better, while the worse 5% yielded a NPV of NOK -20,2 billion or lower. Source: Authors own*

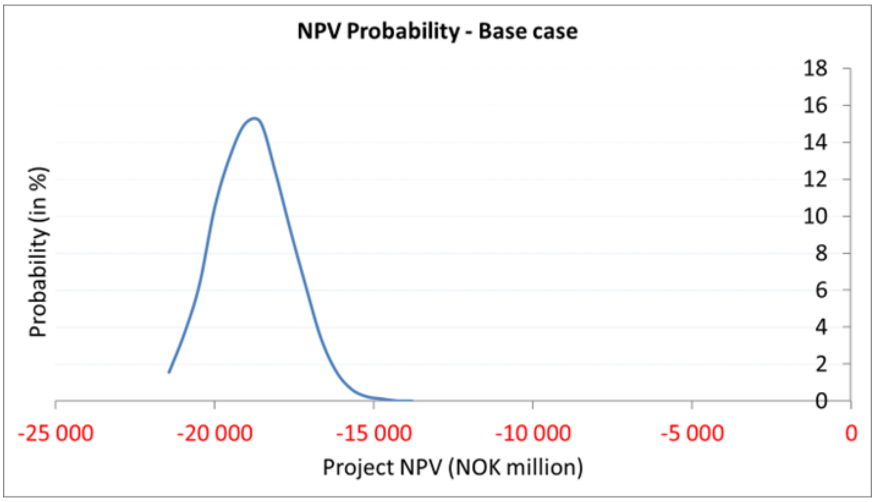

Figure 7.2 *NPV probability distribution for SNII base case in 2030.The most likely NPV observed was NOK -18,5 billion with a probability of 15,2%. Source: Authors own*

7.3.2 Good

The capacity factor obtained an average of 65±2%, with both the 95% and 5% percentile at 65%. A summary of the resulting NPV and IRR in the good case is presented in table 7.6 below.

Present value of project (NPV)		Percentile 5%	Percentile 95%	
Mean	1 381	-370	3 154	NOK mill
Std Dev	1 073			NOK mill
% of cases with PV > 0	90%			
Mean IRR	7%	6%	7%	
Required return (WACC)	6%			

Table 7.6 *Mean value and standard deviation of net present value for SNII good scenario. IRR is shown as well. The 95% and 5% cost percentiles was calculated for both NPV and IRR. Source: Authors own*

With higher growth rate in electricity prices and lower CAPEX and OPEX compared to base scenario, the mean NPV value for Sørlige Nordsjø II was NOK 1,4 ±1,1 billion. The resulting IRR was 7%, higher than the required rate of return of 6%. A total of 90% of the 10 000 simulations yielded a positive present value. The percentile distribution is illustrated in figure 7.3, where NPV in the 95% percentile was NOK ,2 billion. Illustrated in 7.4, the most likely NPV value was NOK 1,1 billion with a probability of 14,8%.

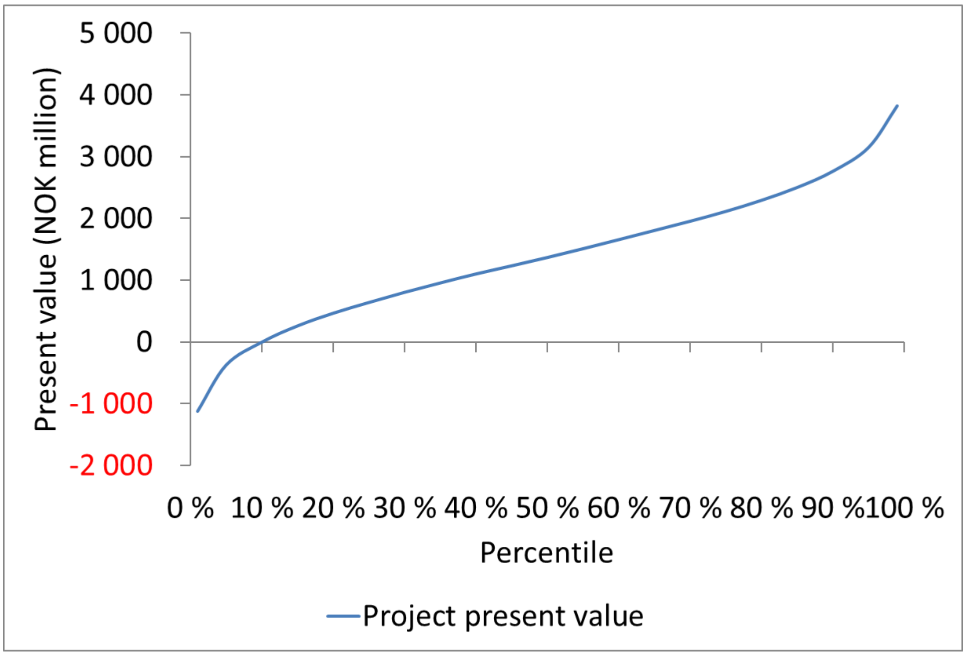

Figure 7.3 *NPV percentile distribution in the good case. The best 5% of the simulations yielded a NPV greater than NOK 3,2 billion, while the lower 5% yielded a NPV of NOK -0,4 billion or lower. Source: Authors own*

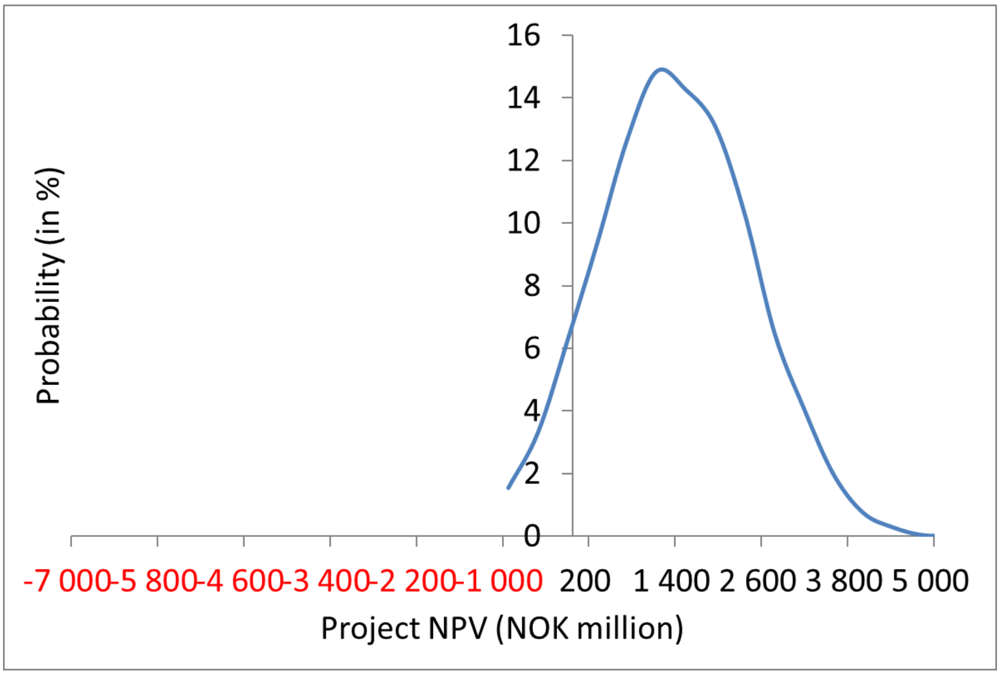

Figure 7.4 *NPV probability distribution for SNII good case in 2030.The most likely NPV observed was NOK 1,1 billion with a probability of 14,8%. Source: Authors own*

7.3.3 Bad

A summary of the resulting NPV and internal rate of return (IRR) in the bad case is presented in table 7.7 below. The average capacity factor was 64±2%, with the 95% and 5% percentile of 65% and 63%, respectively.

		Percentile		
Present value of project (NPV)		**5%**	**95%**	
Mean	-35 484	-37 228	-33 753	NOK mill
Std Dev	754			NOK mill
% of cases with PV > 0	0%			
Mean IRR	N.A.	N.A.	N.A.	
Required return (WACC)	6%			

Table 7.7 *Mean value and standard deviation of net present value for SNII bad scenario. IRR is shown as well. The 95% and 5% cost percentiles were calculated for both NPV and IRR. Source: Authors own*

Down from NOK -18,3 billion in the base case, the mean NPV for Sørlige Nordsjø II was NOK -35,5±0,8 billion in the bad case. The resulting IRR was not available, but significantly lower than the required rate of return of 6%. Out of 10 000 simulations, there were no results that yielded a positive NPV. The percentile distribution can be found in figure 7.5, while the

NPV probability distribution is presented in 7.6 below. The most probable NPV value obtained was NOK -35,7 billion, with a probability of 15%.

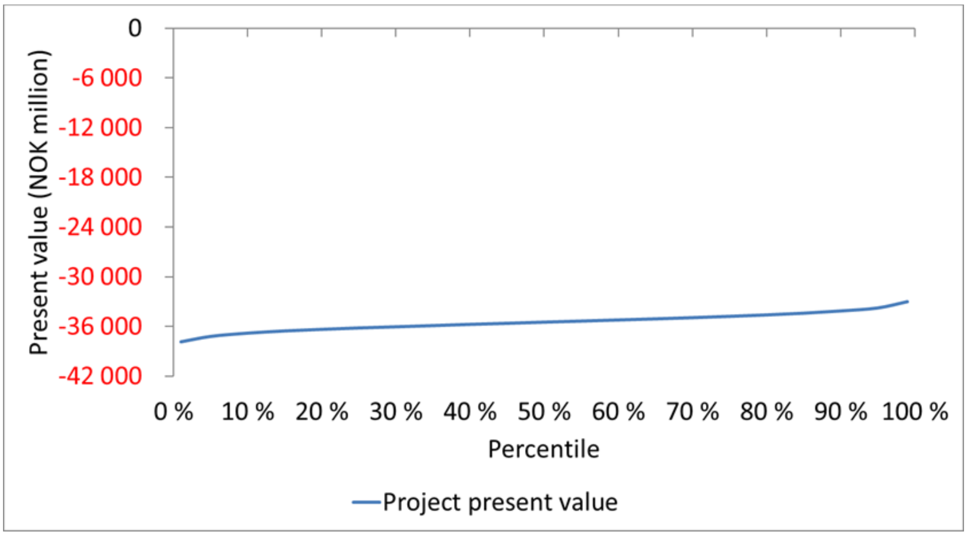

Figure 7.5 *NPV percentile distribution in the bad case. The best 5% of the simulations yielded a NPV of NOK -33,8 billion or better, while the worse 5% yielded a NPV of NOK – 37,2 billion or lower. Source: Authors own*

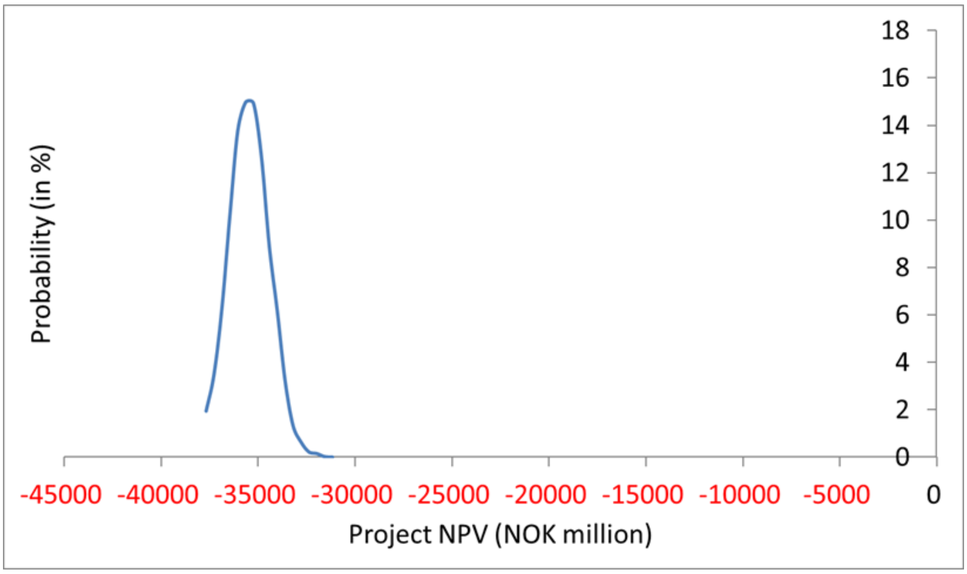

Figure 7.6 *NPV probability distribution for SNII bad case in 2030. The most likely NPV observed was NOK -35,7 billion with a probability of 15%.*

7.3.4 Base

LCOE calculation in the base case of SNII is presented below and yielded a value of NOK 0,68/kWh.

$$LCOE_{base} = \frac{(55\ 378\ 269) + \sum_{t=0}^{25} \frac{(1\ 309\ 633)}{(1+6\%)^{n}} + \frac{3915165}{(1+6\%)^{26}}}{\sum_{t=0}^{25} \frac{8\ 409\ 600}{(1+6\%)^{n}}} = \frac{72\ 980\ 367}{107\ 502\ 912} = \boldsymbol{NOK\ 0,68/kWh}$$

7.3.5 Good

LCOE calculation in the good case of SNII is presented below and yielded a value of NOK 0,55/kWh.

$$LCOE_{good} = \frac{(47\ 703\ 809) + \sum_{t=0}^{28} \frac{(898\ 768)}{(1+6\%)^{n}} + 0}{\sum_{t=0}^{25} \frac{8\ 409\ 600}{(1+6\%)^{n}}} = \frac{59\ 193\ 077}{107\ 502\ 912} = \boldsymbol{NOK\ 0,55/kWh}$$

7.3.6 Bad

LCOE calculation in the good case of SNII is presented below and yielded a value of NOK 0,81/kWh.

$$LCOE_{bad} = \frac{(59\ \ 471\ 314\ ) + \sum_{t=0}^{20} \frac{(1\ 617\ 782)}{(1+6\%)^{n}} + \frac{7830330}{(1+6\%)^{21}}}{\sum_{t=0}^{25} \frac{8\ 409\ 600}{(1+6\%)^{n}}} = \frac{81\ 873\ 813}{107\ 502\ 912} = \boldsymbol{NOK\ 0,81/kWh}$$

8. Discussion

8.1 Summary of findings

The DCF model yielded a negative result in two out of three scenarios for SNII. The bad, base, and good scenario respectively yielded mean present values of NOK -35,5, -18,3, and 1,4 billion. Differences between the scenario results were due to adjustments in: CAPEX, OPEX, DECOM, growth rate of electricity price, project lifetime and years of debt payments. Computed LCOE values were in the range between NOK 0,55-0,81/kWh; a good scenario of 0,55, base scenario of 0,68, and a bad scenario of 0,81. Here, the difference in scenario results represent adjustments made to CAPEX, OPEX, DECOM and project lifetime.

8.2 Interpretation of results

8.2.1 DCF model

The DCF model results indicate that the SNII project is not attractive for an investor. With an initial CAPEX investment of NOK 39 556/kW in the base scenario and a yearly operating cost of approximately NOK 936/kW/year, the result of NOK -18,3 billion is a considerable negative result. NOK 9 million in taxes are paid to the government in this scenario. Since none of the 20 000 simulations yielded a NPV greater than zero, the economic gains in this scenario are absent. This is reflected in the resulting IRR of the project. The equity investor can expect a return on the investment of -4% annually. For the project to be attractive, the investor requires an IRR greater than WACC, in this case 6%.

CAPEX, cost of financing and electricity price seems to be the main contributors to the negative results. For instance, the upfront capital investment of NOK 39 556/kW is 54% higher than estimates by NVE, although this estimate do not account for SNII project specific factors (NVE, 2022a). Since the project is leveraged with 75%, debt payments and interests significantly affects the cash flow the first operational years due to the high project CAPEX. Another element affecting the results is the electricity prices. Although obtaining a high capacity factor of 64% due to great wind conditions, the revenue is ultimately dependent on the electricity price level. As shown in table 8.1 below, the simulated average price in the base case was NOK 0,48/kWh. This is in line with literature forecasts from NVE (2021) estimating a price of 0,54 in 2030 and 0,51 in 2040. However, the base scenario rely on higher electricity prices than this to cover OPEX and financing costs in order to turn profitable.

	Simulation averages			
	Bad	Base	Good	
Capacity factor	64%	64%	65%	
OPEX	1 127	936	683	NOK/kW/year
Annual debt payments	2 124	1 483	1 022	NOK/kW/year
Electricity price	0,44	0,48	0,61	NOK/kWh
Lifetime total tax paid	0	19	9 400	NOK million

Table 8.1 *Simulation averages for SNII in bad, base and good scenario.*
Source: Authors own.

The negative result nearly doubles in the bad scenario compared to base. Obtaining a NPV of NOK -35,5 billion, the project in this scenario is even less attractive for the investor. None of the simulations yielded a positive result. Because of the considerable negative cash flow during operations, the IRR was not attainable. The main contributors to the negative result, CAPEX and the electricity price, were adjusted to a more pessimistic view. CAPEX increased with 7,4% compared to base which entails a higher initial equity investment and annual debt payments and interests. Another contributing factor is the increased OPEX of 24%, reducing the cash flow throughout the project significantly. Revenues decreased due to an 8,3% lower electricity price on average over the lifetime of the project compared to the base case, meaning less revenues to cover the increased yearly financing costs.

Contrary to the bad and base case, the good case was promising with regards to the profitability of the project. The NPV was greater than zero in 90% of the simulations, indicating that the project yielded positive cash flows during the economic lifetime. The IRR was 7%, one percentage point above the required return of 6%. In effect, the investment yielded an annual return of 7% during the lifetime of the project, making it economically preferrable for the equity investor. Higher profits than the base case resulted in increased taxes paid, benefitting the government. Here, SNII generated a total of NOK 9 400 million in taxes compared to NOK 9 million in the base case. The reduction in CAPEX and OPEX from base case in addition to higher growth rate in electricity prices significantly contributed to the increased profitability in the good scenario. The electricity price was on average 27% greater in the good scenario compared to base, benefitting from the 3% annual growth rate. Additionally, lower OPEX costs ensured an EBITDA covering both debt payments and interests, yielding positive cash flow. Increasing project lifetime from 25 to 28 years from base case and debt payment period by 5 years from 20 further distributed the costs over a longer period.

LCOE

LCOE is the minimum cost of generating electricity and can be interpreted as the break-even point the developer need to realize per unit of electricity (ORI, 2015). The estimated LCOE in this thesis is consistent with some of the literature forecasting LCOE in the North Sea, see table 8.2. NVE estimate a LCOE for SNII in 2030 to be NOK 0,60/kWh over the project lifetime, with a lower and upper range of NOK 0,48 and 0,68/kWh (NVE, 2021). The results are to some extent in accordance with NVE's estimates. However, NVE points out that they have not done any precise cost calculations for SNII (NVE, 2022a). Due to lack of readable data, Statnett has not done precise calculations for offshore wind in Norway but assume the price for bottom-fixed OW in the Norwegian shelf to be somewhat above NOK 0,50-0,60/kWh (Statnett, 2021). Furthermore, WindEurope (2019) estimate that LCOE for the surrounding area of SNII is set to be between €65-80/MWh in 2030 (WindEurope, 2019) Converted to NOK, this is equivalent to a LCOE of NOK 0,63 to 0,78/kWh.

Publisher	Forecast year		LCOE	Including grid connection	Original	Comments
WindEurope	2030	NOK/kWh	0,63 - 0,78	Yes	65 to 80 €/MWh	15MW
NVE	2030	NOK/kWh	0,48 - 0,68	Yes		Jacket
Statnett	2030	NOK/kWh	0,50 - 0,60	Yes		Norwegian shelf

Table 8.2 *Summary of forecasted LCOE values for Sørlige Nordsjø II as presented in the literature. Source: (WindEurope, 2019), (OED, 2020-2021) , (Statnett, 2021).*

Comparing our LCOE results of NOK 0,55-0,81/kWh with projected electricity prices in Norway, none of the results seems to break even. NVE (2021) estimate a price of NOK 0,54/kWh in 2030 and 0,51 in 2040, while Statnett (2020) obtain a somewhat lower estimate of NOK 0,33-0,39/kWh. Using the LCOE as a break even metric for the developer, the projected electricity price will not yield any profits. Although LCOE might not reflect the exact cost level, it gives an indication of what is required to become profitable.

As in the DCF model, the CAPEX and OPEX were the main contributors to the high LCOE level. However, the static capacity factor of 64% provided a high annual energy production. Following the LCOE equation, a high AEP denominator thus provides a better result. In addition, debt payments and interests during the project lifetime are not represented in the

LCOE results due to 100% equity financing. Thus, the negative cash flow has a greater NPV in year 0 compared to the DCF-model, which spread the investment over several years in comparison. If the debt interest rate is lower than WACC, the latter is preferrable regarding profitability.

8.3 Implications

Government support

Following a negative net present value for the project, several implications and questions arise. The simulated results imply that current OW cost estimates are underestimated, mainly driven by using public domain sources rather than actual costs derived by audited accounts. The mean NPV for the bad, base, and good case were NOK -35,5, -18,3 and 1,4 billion, respectively. Scenario values for LCOE were NOK 0,81, 0,68 and 0,55/kWh, respectively. The simulated results for Sørlige Nordsjø II assume no governmental support, and a direct radial connection to the Norwegian mainland. From an investors point of view, an investment would be unprofitable and not preferable in the base and bad scenario. This might lower the investment interest among developers seeking to capitalize on OWF deployment in the North Sea. As such, questions regarding governmental aid arise. The government can offer state aid to promote investments until costs have fallen enough to break even. If subsidies are provided through CfD auctions, the revenue risk and associated cost of financing will decrease as mentioned in chapter 5.3.6. This imply that the project attractiveness increases for potential investors.

Depending on the timeline of the support and objective of the deployment, further questions regarding the cost of subsidies compared to cost of electricity arise. At the end of the day, someone must bear the cost of the unprofitable OW development. Subsidies will inevitably increase the governmental cost, potentially leading to a cost increase for taxpayers. On the contrary, without subsidies, the risk of no development increases due to the estimated low financial returns. Furthermore, this could result in lower future supply of power to NO2 grid, yielding higher prices for the consumers all else equal. Though beyond the scope of this thesis, the tradeoff between potential higher power prices from integration of unprofitable OWFs or potential higher costs for taxpayers because of subsidies can be investigated.

Power prices

Beyond cost reductions, a profitable deployment of Sørlige Nordsjø II depend on higher power prices according to the negative DCF results. Increasing the power price growth in the good scenario significantly increased the project cash flow. Although several other input variables were adjusted from the base case, higher power prices point out as a vital element to secure profitability. As mentioned in chapter 4.4.2 Statnett (2020) expects a power price of NOK 0,35 to 0,38/kWh after 2030 in south of Norway. Meanwhile, NVE (2021) suggests prices between NOK 0,42 to 0,70/kWh in 2030 and 0,38 to 0,65 in 2040. The base case LCOE result is in the upper power price range forecasted by NVE and Statnett. This gives a fair indication that if SNII shall be profitable without subsidies, the project must either rely on higher power prices or lower costs. This thesis has considered a radial connection to the mainland, thus any potential higher power prices from nearby countries such as the UK, Germany or Netherlands is ignored. In general, prices in these countries are set to be 10-20% higher than prices in the Nordic countries between 2030 and 2040 (NVE, 2021). However, examination of the correlation between wind production and power prices across borders should be considered in a case with hybrid cables. Hence, utilizing higher power prices outside the mainland are highly dependent on this correlation. Additionally, potential economies of scale effects of connecting to a future North Sea wind power hub is neglected in the thesis. Statnett recently published an analysis of the second phase of SNII with hybrid cables (Statnett, 2022). Thus, it would be interesting to build on this in further work using audited accounts.

Need for renewable energy

A negative net present value does not automatically exclude offshore wind deployment. The need for renewable sources in the transition from fossil fuelled energy is pressing. There are reasons to believe investments in OWFs are too important to let go in terms of increasing the renewable share in total energy mix. If EU are to fulfil the goal of becoming the first climate neutral continent within 2050, solutions such as OW might be needed for better or worse. Thus, the cost of this transition might be something investors and public would be willing to pay for in the short term. An interesting theme for further work beyond this thesis would be to examinate if newly entered renewable energy developers make bids lower than their actual break even cost level. If that is the case, reasons why would be interesting to uncover. A cost premium in the long run is however more challenging to justify, and examination of this would be interesting in further work.

Rely on cost reductions

OWF development heavily relies on actual decrease in costs over time. The good case scenario with 14% reduction in CAPEX and 31% for OPEX as compared to base scenario yielded a positive NPV of NOK 1,4 billion. This includes a power price increase of 3%, significantly higher than literature forecasts. If OWF projects obtain this scenario trajectory, the need for governmental support is reduced or even unnecessary. The positive result in this scenario imply that offshore wind might be profitable from 2030 and onwards. However, for the industry to develop in accordance with the good scenario, major initiatives to promote OW power is necessary. Providing jobs, revenues and potential export opportunities for future projects, offshore wind might be an industry worth going for. Needless to say, the NPV of NOK 1,4 billion is comparable low when considering the initial total investment of NOK 55,4 billion.

8.4 Limitations to results

One of the major risks when conducting a profitability analysis is uncertainty in estimates. Thorough this thesis, different model input has been obtained and calculated with a fair consideration. A transparent approach has been the objective by utilizing several and reliable sources. In addition, audited accounts subject to International Accounting Standards secure that figures are free from material misstatements, further increasing the reliability. However, it should be noted that the dataset of actual costs comprises of 38 offshore wind farms in the UK. Ideally, the analysis would benefit a comparison across additional wind farms and across multiple countries. Nevertheless, actual cost data is not easy to obtain, and governmental policy differences in how transmission assets are treated could make it more challenging to compare.

Regarding estimates for the future, cost projections for the upcoming decade are a matter of probabilities and yields great uncertainty. Projected values for project CAPEX and OPEX are sought to reflect the historic development and future technological enhancements, but the authors recognize the accompanied uncertainty that follows. Caution should be made to the given scenario cost reductions leading up to 2030, given it is partly derived from literature expectations in addition to authors' own estimates. A standard sensitivity analysis could have been conducted to investigate effects of changing cost-parameters. However, the results in the case study using MCS would differ from one simulation to another, making the changes incomparable. Hence, there is not performed such an analysis, and including it could possibly lead to other findings than presented in this thesis. The same goes for predicating future electricity prices. Knowing that an increased price heavily influences the profitability of an OWF, precise values are preferable.

In the model, bottleneck revenues are not included as prices are averaged over a month. Thus, the effect of short-term hourly, daily and weekly extreme price fluctuations will as a consequence not be captured in the model. This is supported by Statnett (2022), stating that socio-economic benefits can be onbtained when utilizing short term price fluctuations observed at trade countries. Statnett further stress that short term price fluctuations are greater in the UK than in Norway. Hence, including hourly price data combined with hybrid cables to nearby countries could positively impact the results presented in this thesis.

Despite having the benefit of allowing dynamic modelling and simulations of results, the NPV obtained from the Discounted Cash Flow model are due to some disadvantages. Farm layout is not modelled, hence wake loss is not considered in the scope of this thesis. A real-world scenario would have wake loss in addition to other production losses totaling somewhat lower annual output. This includes yearly performance decrease as the machinery ages. According to Staffell & Green (2014), this has been observed to be 1,6±0,2% per year of annual output, amounting to a 12% decrease in output over a 20 year lifetime. However, we have not included such in our model due to computational limitations when simulating the results. As a consequence, results presented in this thesis might differ from a model including this.

In both literature and public debate, cost of different energy sources is usually reported as levelized costs of energy (LCOE). Its ability to compare across OWF projects as well as other energy sources in a simple matter is beneficial. However, the shortcomings due to the static modelling in LCOE are handled by the inclusion of the NPV-model. Both of these model value cash flow close to the project start compared to later years. This disfavors OWF projects with high upfront capital cost and high equity-to-debt ratio resulting high cost of finance in early years. This is particularly of relevance in the choice of discount rate. We have chosen not to use different discount rates for each scenario due to the mostly negative cash flow obtained in the simulations. A lower WACC will in general yield higher discounted cash flows, resulting in a more negative NPV if the initial cash flow is negative. Hence, the true effect of changing the discount rate is not reflected in this thesis.

9. Conclusion & recommendations

As the scale of major global offshore wind initiatives grows, so does the importance of understanding the long-term profitability of future projects. To answer the research question, a review of historic project costs in audited accounts from 38 UK offshore wind farms' SPVs has been conducted. The thesis contains a profitability analysis of deploying 1400 MW capacity in Sørlige Nordsjø II (SNII) in 2030, assuming a radial connection to the Norwegian mainline grid NO2 and no subsidies. The analysis was conducted by applying a DCF model with MCS as well as calculating a LCOE.

Results from the DCF-model imply that offshore wind development for the first phase of SNII will not profitable. Relying on optimistic assumptions, a "good" case out of three scenarios yielded positive NPV, even though relatively small in relation to the negative base- and bad case. The LCOE results yielded figures between NOK 0,55-0,81/kWh, to some extent in line with literature estimates for SNII.

With no governmental subsidies and no hybrid cables, the negative results obtained in the DCF model imply that development of SNII is unattractive for investors. This could potentially reduce the future interest among investors. Subsidies will increase the attractiveness of the project but will bring about a cost for the government. Additionally, the project profitability could be improved by higher power prices. However, prices in NO2 are on average lower compared to trade partners. This thesis has discussed if a hybrid cable could increase the profitability for SNII. However, whether wind power production at SNII can benefit from higher power prices at trade partners or not was not examined in this thesis. A negative NPV does not automatically exclude offshore wind deployment, as the need for renewable energy sources are increasing. Further analysis could examine the willingness to pay for electricity provided by offshore wind. This thesis also found that significant technological cost developments, more efficient supply chain operations as well as a substantial growth in electricity price are needed to overcome profitability obstacles. The good case scenario illustrated that this barely yielded a positive NPV. This indicates that a profitable development of SNII depends on significant cost reductions, higher electricity price or major governmental subsidies to become profitable.

Based on an economic assessment of actual costs and projected industry development, we do not recommend Sørlige Nordsjø II to be developed.

10. References

Aldersey-Williams, J., & Rubert, T. (2019a). Levelised cost of energy – A theoretical justification and critical assessment. *Energy policy, 124*, pp. 169-179. doi:https://doi.org/10.1016/j.enpol.2018.10.004.

Aldersey-Williams, J., Broadbent, I., & Strachan, P. (2019b). Better estimates of LCOE from audited accounts – A new methodology with examples from United Kingdom offshore wind and CCGT. *128*, pp. 25-35. doi:https://doi.org/10.1016/j.enpol.2018.12.044

Arup. (2018). *Onshore wind financing; Cost of Capital Benefits of Revenue Stabilization via a Contract for Difference.* Arup. Retrieved from https://www.arup.com/-/media/arup/files/publications/o/onshore-wind-cost-of-capital-report.

Aures II. (2021). *Renewable energy financing conditions in Europe: survey and impact analysis.* Auctions for Renewable Energy Support II. Retrieved from https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5daaba9f4&appId=PPGMS

Baring-Gould, I. (2014). *Offshore Wind Plant Electrical Systems.* National Renewable Energy Laboratory. Retrieved 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

BEIS. (2016). *Electricity generation costs.* London: Department for Business, Energy & Industrial Strategy. Retrieved from https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

BEIS. (2020). *Electricity Generation Costs 2020.* London: Department for Business, Energy & Industrial Strategy. Retrieved from https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

Betz, A. (1920). Das Maximum der theoretisch möglichen Ausnützung des Windes durch Windmotoren. *Zeitschrift für das gesamte Turbinenwesen, 26*, 307-309.

Bosch, J., Staffell, I., & Hawkes, A. D. (2019). Global levelised cost of electricity from offshore wind. *Energy, 189*. doi:https://doi.org/10.1016/j.energy.2019.116357

BOW. (2020, Mai). *Havvind - enkelt forklart.* Bergen Offshore Wind Centre. Retrieved from https://www.uib.no/sites/w3.uib.no/files/attachments/havvind_enkelt_forklart.pdf

BVG Associates. (2019). *Guide to an offshore wind farm: Updated and extended.* BVG Associates. Retrieved from https://www.thecrownestate.co.uk/media/2860/guide-to-offshore-wind-farm-2019.pdf

BVG Associates. (2022, April 15). *Wind farm costs*. Retrieved 2022 April, from Guide to an offshore wind farm: https://guidetoanoffshorewindfarm.com/wind-farm-costs

Crabtree, C. J., Zappala, D., & Hogg, S. I. (2015). Wind energy: UK experiences and offshore operational challenges. *229 (7)*, pp. 727–746. doi:10.1177/0957650915597560

EC. (2020). *An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future.* Brussels: European Commission. Retrieved from https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0741&from=EN

Eide, C. H. (2022, March 23). *Offshore wind in Utsira and Sørlige Nordsjø II, phase I; what now?* Retrieved March 2022, from University of Bergen: https://www.uib.no/en/energy/151917/offshore-wind-utsira-and-sørlige-nordsjø-ii-phase-i-what-now

Engie. (2021, September 8). *Can wind turbines be recycled?* Retrieved April 21, 2022, from Engie: https://www.engie.com/en/activities/renewable-energies/wind-energy/recycling-wind-turbines

Equinor. (n.d.). *Floating wind*. Retrieved April 12, 2022, from Equinor: https://www.equinor.com/energy/floating-wind

Equnior. (n.d.). *Hywind Tampen.* Retrieved May 2022, from Equinor: https://www.equinor.com/energy/hywind-tampen

EWEA. (2009). *The Economics of Wind Energy.* European Wind Energy Association. Retrieved from https://www.ewea.org/fileadmin/files/library/publications/reports/Economics_of_Wind_Energy.pdf

GE. (2022). *Haliade-X offshore wind turbine*. Retrieved March 20, 2022, from GE Renewable Energy: https://www.ge.com/renewableenergy/wind-energy/offshore-wind/haliade-x-offshore-turbine

Greenstat. (2021). *Optimal utnyttelse av energi fra havvind i Sørlige Nordsjø II.* Bergen: Greenstat. Retrieved from https://greenstat.no/assets/downloads/optimal-utnyttelse-av-energi-fra-havvind-i-sorlige-nordsjo-ii_hr-tn.pdf

GWEC. (2021). *Global offshore wind report 2021.* Global Wind Energy Council. Retrieved from https://gwec.net/global-offshore-wind-report-2021/

Hughes, G. (2020). Wind Power Economics Rhetoric & Reality. *Wind Power Cost in the United Kingdom, 1*. Retrieved from https://www.ref.org.uk/Files/performance-wind-power-uk.pdf

IEA. (2011). *World Energy Outlook 2011.* International Energy Agency. Retrieved from https://www.iea.org/reports/world-energy-outlook-2011

IEA. (2019). *Offshore Wind Outlook 2019.* International Energy Agency. Retrieved from https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf

IEA. (2021). *World Energy Outlook 2021.* International Energy Outlook. Retrieved from https://www.iea.org/reports/world-energy-outlook-2021

IEA. (2021a, December 17). *The cost of capital in clean energy transitions.* Retrieved April 2022, from IEA: https://www.iea.org/articles/the-cost-of-capital-in-clean-energy-transitions

IEA. (2021b). *Wind Power*. Retrieved May 2022, from IEA: https://www.iea.org/reports/wind-power

IRENA. (2015). *Renewable energy auctions: A guide to design.* IRENA. Retrieved from https://www.irena.org/publications/2015/Jun/Renewable-Energy-Auctions-A-Guide-to-Design

IRENA. (2016). *Innovation outlook: Offshore wind.* International Renewable Energy Agency. Retrieved from https://www.irena.org/publications/2016/Oct/Innovation-Outlook-Offshore-Wind

IRENA. (2019). *Future of wind: Deployment, investment, technology, grid integration and socio-economic aspects.* Abu Dhabi: International Renewable Energy Agency. Retrieved from https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf

IRENA. (2019). *Renewable energy auctions: Status and trends beyond price.* IRENA. Retrieved from https://www.irena.org/-/media/files/irena/agency/publication/2019/oct/irena_future_of_wind_2019.pdf

IRENA. (2021). *Renewable Power Generation Costs in 2020.* Abu Dhabi: International Renewable Energy Agency. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jun/IRENA_Power_Generation_Costs_2020.pdf

IRENA. (2022). *Renewable Technology Innovation Indicators: Mapping progress in costs, patents and standards.* International Renewable Agency. Retrieved from https://www.irena.org/publications/2022/Mar/Renewable-Technology-Innovation-Indicators

Johnston, B., Foley, A., Doran, J., & Littler, T. (2020). Levelised cost of energy, A challenge for offshore wind. *Renewable Energy, 160*, pp. 876-885. doi:https://doi.org/10.1016/j.renene.2020.06.030

Judge, F., McAuliffe, F. D., Sperstad, I. B., Chester, R., Flannery, B., Lynch, K., & Murphy, J. (2019). A lifecycle financial analysis model for offshore wind farms. *103*, pp. 370-383. doi:https://doi.org/10.1016/j.rser.2018.12.045

Keivanpour, S., Ramudhin, A., & Kadi, D. A. (2017). The sustainable worldwide offshore wind energy potential: A systematic review. *Journal of Renewable and Sustainable Energy, 9*. doi:https://doi.org/10.1063/1.5009948

Lacal-Aránteguia, R., Yusta, J. M., & Domínguez-Navarro, J. A. (2018). Offshore wind installation: Analysing the evidence behind improvements in installation time.

Renewable and Sustainable Energy Reviews, 92, pp. 133-145. doi:https://doi.org/10.1016/j.rser.2018.04.044

Lee, S.-C. (2011). Using real option analysis for highly uncertain technology investments: The case of wind energy technology. *9*, pp. 4443–4450. doi:https://doi.org/10.1016/j.rser.2011.07.107

Letcher, T. M. (2017). *Wind Energy Engineering: A handbook for Onshore and Offshore Wind Turbines.* Elsevier Inc.

Lewis, M. (2021, october 5). *GE's huge Haliade-X 14 MW offshore wind turbine is now operational*. Retrieved april 6, 2022, from Electrec: https://electrek.co/2021/10/05/ge-huge-haliade-x-14-mw-offshore-wind-turbine-is-now-operational/

Liu, Q., Sun, Y., & Mengcheng, W. (2021). Decision-making methodologies in offshore wind power investments: A review. *Journal of Cleaner Production, 295*, pp. 1-19. doi:https://doi.org/10.1016/j.jclepro.2021.126459

Lydia, M., Suresh Kumar, S., Immanuel Selvakumar, A., & Kumar, E. p. (2014, Februar). A comprehensive review on wind turbine power curve modeling techniques. *Renewable and Sustainable Energy Reviews, 2014 (30)*, pp. 452-460. doi:doi.org/10.1016/j.rser.2013.10.030

Matthäus, D. (2020, July). Designing effective auctions for renewable energy support. *Energy Policy, 142*, p. 2. doi:https://doi.org/10.1016/j.enpol.2020.111462

McKinsey & Company. (2018). Merchant risk management: The new frontier in renewables. Retrieved from https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/merchant-risk-management-the-new-frontier-in-renewables

Meissner, M. (2021). Offshore Wind Turbine cost scaling - A critical Assessment and theoretical Investigation. EAB. Retrieved from https://www.researchgate.net/publication/348356086_Offshore_Wind_Turbine_cost_scaling_-A_critical_Assessment_and_theoretical_Investigation

Menon Economics. (2020, Oktober). *Virkemidler for å realisere flytende havvind på norsk sokkel.* Menon. Retrieved from https://www.menon.no/wp-content/uploads/2020-116-Virkemidler-for-%C3%A5-realisere-flytende-havvind-p%C3%A5-norsk-sokkel.pdf

Nera Economic Consulting. (2015). *Electricity Generation Costs and Hurdle Rates.* Nera Economic Consulting. Retrieved from https://www.nera.com/content/dam/nera/publications/2016/NERA_Hurdle_Rates_for_Electricity_Generation_Technologies.pdf

Nord Pool. (n.d). *List of changes in day-ahead and intraday areas.* Retrieved 2022, from Nord Pool: https://www.nordpoolgroup.com/4a7b04/globalassets/download-center/day-ahead/elspot-area-change-log.pdf

Norges Bank. (2019). Nibor, Libor and Euribor – all IBORs, but different. *Staff memo, 2*. Retrieved from https://www.norges-bank.no/contentassets/607da26db8df45a7983e135b73fa724e/staff_memo_2_2019_eng.pdf?v=03/01/2019101404&ft=.pdf&v=03/01/2019101404&ft=.pdf

North Wind. (2022). *Marine Operations and Logistics*. Retrieved March 22, 2022, from North Wind: https://www.northwindresearch.no/marine-operations-and-logistics/

Norwegian Government. (2022a, February 09). *Major initiative to promote offshore wind power*. Retrieved May 2022, from Goverment.no: https://www.regjeringen.no/en/aktuelt/major-initiative-to-promote-offshore-wind-power/id2900436/

Norwegian Government. (2022b, may 11). *Ambitious offshore wind initiative*. Retrieved May 22, 2022, from Government.no: https://www.regjeringen.no/en/aktuelt/ambitious-offshore-wind-power-initiative/id2912297/

NREL. (2020). *Definition of the IEA 15-Megawatt Offshore Reference Wind.* National Renewable Energy Laboratory. Retrieved may 2022, from https://www.nrel.gov/docs/fy20osti/75698.pdf

NREL. (2020). *Offshore Wind Turbine Documentation.* Retrieved May 2022, from Github: https://nrel.github.io/turbine-models/2020ATB_NREL_Reference_15MW_240.html

NSWPH. (2021). *Towards the first hub-and-spoke project.* North Sea Wind Power Hub. Retrieved from https://northseawindpowerhub.eu/sites/northseawindpowerhub.eu/files/media/document/NSWPH_Concept%20Paper_05_2021_v2.pdf

NVE. (2012). *Havind: Strategisk konsekvensutredning.* Norges vassdrag- og energidirektorat. NVE. Retrieved from https://publikasjoner.nve.no/rapport/2012/rapport2012_47.pdf

NVE. (2019). *Dybde og kompliserte bunnforhold gjør havvind i Norge dyrere enn i Europa.* Oslo: Norges vassdrag- og energidirektorat. Retrieved from http://publikasjoner.nve.no/faktaark/2019/faktaark2019_15.pdf

NVE. (2019). *Hydrogen i det moderne energisystemet.* Norges vassdrag- og energidirektorat. Retrieved from https://publikasjoner.nve.no/faktaark/2019/faktaark2019_12.pdf

NVE. (2020, May 18). *Havvind i Norge.* Retrieved May 2022, from NVE: https://www.nve.no/energi/energisystem/vindkraft/havvind-i-norge/

NVE. (2021). *Langsiktig kraftmarkedsanalyse 2021-2040.* Norges vassdrag- og energidirektorat. Retrieved from https://publikasjoner.nve.no/rapport/2021/rapport2021_29.pdf

NVE. (2021, Juni 28). *Norway and the European power market*. (Norges vassdrag- og energidirektorat) Retrieved March 2022, from NVE: https://2021.nve.no/norwegian-energy-regulatory-authority/wholesale-market/norway-and-the-european-power-market/

NVE. (2022a, January 31). *Kostnader for kraftproduksjon*. Retrieved February 25, 2022, from NVE: https://www.nve.no/energi/analyser-og-statistikk/kostnader-for-kraftproduksjon/

NVE. (2022b). *Elsertifikater*. (Norges vassdrag- og energidirektorat) Retrieved April 2022, from NVE: https://www.nve.no/energi/virkemidler/elsertifikater/

OED. (2020, June 12). Opning av områda Utsira Nord og Sørlige Nordsjø II for konsesjonshandsaming av søknader om fornybar energiproduksjon etter havenergilova. *Opning av områda Utsira Nord og Sørlige Nordsjø II for konsesjonshandsaming av søknader om fornybar energiproduksjon etter havenergilova*. Olje- og energidepartmentet. Retrieved from https://www.regjeringen.no/contentassets/aaac5c76aec242f09112ffdceabd6c64/kgl.res-12.-juni-2020-opning-av-omrade-for-fornybar-energiproduksjon-til-havs.pdf

OED. (2020-2021). *Energi til arbeid – langsiktig verdiskaping fra norske energiressurser.* Det Kongelige Olje- og Energidepartement. Retrieved from https://www.regjeringen.no/no/dokumenter/meld.-st.-36-20202021/id2860081/

OED. (2021, October 12). *Kraftmarkedet og strømpris*. Retrieved from Regjeringen.no: https://www.regjeringen.no/no/tema/energi/stromnettet/kraftmarkedet-og-strompris/id2076000/

OIES. (2019). Auctions for allocation of offshore wind contracts for difference in the UK. *Oxford Institute for Energy Studies, 33*. doi:DOI: https://doi.org/10.26889/9781784671297

ORI. (2015). *A review of levelised cost of energy, as applied to offshore wind industry.* Offshore Renewables Institute (ORI). Retrieved from https://www.researchgate.net/publication/320410287_A_REVIEW_OF_LEVELISED_COST_OF_ENERGY_AS_APPLIED_TO_THE_OFFSHORE_WIND_INDUSTRY

PeakWind. (n.d.). *OPEX Benchmark – An insight into operational expenditures of European offshore wind farms*. Retrieved april 11, 2022, from PeakWind: https://peak-wind.com/insights/opex-benchmark-an-insight-into-operational-expenditures-of-european-offshore-wind-farms/

Plenborg, T., & Kinserdal, F. (2021). *Financial statement analysis* (Vol. II). Bergen: Fagbokforlaget.

PWC. (2020). *Financing offshore wind.* PriceWaterhouseCoopers. Retrieved from https://www.pwc.nl/nl/actueel-publicaties/assets/pdfs/pwc-invest-nl-financing-offshore-wind.pdf

Raychaudhuri, S. (2008). Introduction to Monte Carlo simulation. 91-100. USA. Retrieved from https://www.informs-sim.org/wsc08papers/012.pdf

RiskAMP. (n.d.). *The beta-PERT Distribution*. Retrieved May 11, 2022, from RiskAMP: https://www.riskamp.com/beta-pert

Rystad Energy. (2020, september 17). *Size matters in offshore wind: Why costlier 14 MW turbines actually reduce the large-scale farm bill*. Retrieved april 21, 2022, from Rystad Energy: https://www.rystadenergy.com/newsevents/news/press-releases/size-matters-in-offshore-wind-why-costlier-14-mw-turbines-actually-reduce-the-large-scale-farm-bill/

Rystad Energy. (2021, April 29). *An expenditure splash of $810 billion is expected for the offshore wind industry this decade*. Retrieved April 16, 2022, from Rystad Energy: https://www.rystadenergy.com/newsevents/news/press-releases/an-expenditure-splash-of-%24810-billion-is-expected-for-the-offshore-wind-industry-this-decade

Salm, S. (2018, Februar). The investor-specific price of renewable energy project risk – A choice experiment with incumbent utilities and institutional investors. *Renewable and Sustainable Energy Reviews, 82*, pp. 1364-1375. doi:https://doi.org/10.1016/j.rser.2017.04.009

Sánchez, S., López-Gutiérrez, J.-S., Negro, V., & Esteban, M. D. (2019). Foundations in Offshore Wind Farms: Evolution, Characteristics and Range of Use. Analysis of Main Dimensional Parameters in Monopile Foundations. p. 441. doi:10.3390/jmse7120441

Shafiee, M., & Adedipe, T. (2022). Offshore wind decommissioning: an assessment of the risk of operations. *International Journal of Sustainable Energy*. doi:https://doi.org/10.1080/14786451.2021.2024830

Shields, M., Beiter, P., Nunemaker, J., Cooperman, A., & Duffy, P. (2021). Impacts of turbine and plant upsizing on the levelized cost of energy for offshore wind. *298*, pp. 1-13. doi:https://doi.org/10.1016/j.apenergy.2021.117189

Shreives, R. E., & Wachowicz jr., J. M. (2001). Free Cash Flow (FCF), Economic Value Added (EVA), and Net Present Value (NPV): A reconcilation of variations of

Discounted-Cash-Flow (DCF) valuation. *The Engineering Economist, 46*(1), pp. 33-52. doi:10.1080/00137910108967561

SSB. (2022). *Konsumprisindeksen*. Retrieved April 2022, from Statistisk sentralbyrå: https://www.ssb.no/priser-og-prisindekser/konsumpriser/statistikk/konsumprisindeksen

SSE. (2021, december 2). *SSE Renewables*. Retrieved may 5, 2022, from Dogger Bank C reaches financial close: https://www.sse.com/news-and-views/2021/12/dogger-bank-c-reaches-financial-close/

SSE Renewable Energy. (n.d.). *Dogger Bank wind farm: Building the world's largest offshore wind farm*. Retrieved April 12, 2022, from SSE Renewable Energy: https://www.sserenewables.com/offshore-wind/projects/dogger-bank/

SSE Renewables. (n.d.). *Seagreen offshore wind farm*. Retrieved April 11, 2022, from SSE Renewables: https://www.sserenewables.com/offshore-wind/projects/seagreen/

Staffell, I., & Green, R. (2014). How does wind farm performance decline with age? *Renewable Energy, 66*, pp. 775-786. doi:https://doi.org/10.1016/j.renene.2013.10.041

Statista. (2022, May 5). *Offshore wind energy capacity worldwide from 2009 to 2021*. Retrieved may 18, 2022, from Statista: https://www.statista.com/statistics/476327/global-capacity-of-offshore-wind-energy/

Statkraft. (2022). *Slik virker det: Hvorfor går strømprisen opp?* Retrieved March 2022, from Statkraft: https://www.statkraft.no/nyheter/nyheter-og-pressemeldinger/arkiv/2021/slik-virker-det-hvorfor-gar-stromprisen-opp/

Statnett. (2018, October 10). *Slik-fungerer-kraftsystemet*. Retrieved May 2022, from Statnett: https://www.statnett.no/om-statnett/bli-bedre-kjent-med-statnett/slik-fungerer-kraftsystemet/

Statnett. (2020). *Langsiktig markedsanalyse.* Statnett. Retrieved from https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/lma/langsiktig-markedsanalyse-norden-og-europa-2020-50_revidert.pdf

Statnett. (2021). *Long-term Market Analysis 2020-2050 - Update Spring 2021.* Retrieved Mai 2022, from Statnett: https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/lma/lma-update-2021.pdf

Statnett. (2022). *Fagrapport om havvind i Sørlige Nordsjø 2.* Oslo. Retrieved from https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/havvind/fagrapport-om-havvind-i-sorlige-nordsjo-ii.pdf

Steffen, B. (2020). Estimation the cost of capital for renewable energy projects. *Energy Economics*(88). doi:https://doi.org/10.1016/j.eneco.2020.104783

Stehly, T., Beiter, P., & Duffy, P. (2020). *2019 Cost of Wind Energy Review.* NREL. Retrieved february 27, 2022, from https://www.nrel.gov/docs/fy21osti/78471.pdf

Stortingets skattevedtak, 2022, §75. (n.d.). Stortingsvedtak om skatt av inntekt og formue mv. for inntektsåret 2022 (LOV-1814-05-17-§75). Retrieved from https://lovdata.no/dokument/STV/forskrift/2021-12-14-3571

Tagliapietra, S., Zachmann, G., & Fredriksson, G. (2019, August). Estimating the cost of capital for wind energy investments in Turkey. *Energy Policy, 2019*(131), pp. 295-301. doi:https://doi.org/10.1016/j.enpol.2019.05.011

TenneT. (2020, february 13). *TenneT develops first 2GW offshore grid connection with suppliers*. Retrieved from TenneT: https://www.tennet.eu/tinyurl-storage/detail/tennet-develops-first-2gw-offshore-grid-connection-with-suppliers/

Thema Consulting. (2020). *Offshore Wind - opportunities for the Norwegian Industry.* Oslo: Thema Consulting. Retrieved from https://www.regjeringen.no/contentassets/07635c56b2824103909fab5f31f81469/offshore-wind-opportunities-for-the-norwegian-industry.pdf

Toftegaard Hansen, J., MahakIakovos, M., & Tzanakis, I. (2021). Numerical modelling and optimization of vertical axis wind turbine pairs: A scale up approach. *Renewable Energy*, 1371-1381. doi:https://doi.org/10.1016/j.renene.2021.03.001

UN. (2022). *COP26: Together for our planet*. Retrieved May 18, 2022, from United Nations: https://www.un.org/en/climatechange/cop26

Vieira, M., Snyder, B., Henriques, E., & Reis, L. (2019). European offshore wind capital cost trends up to 2020. *Energy Policy, 129*, pp. 1364-1371. doi:https://doi.org/10.1016/j.enpol.2019.03.036

Voormolen, J., Junginger, H., & van Sark, W. (2015). Unravelling historical cost developments of offshore wind energy in Europe. *Energy Policy, 88*, pp. 435–444. doi:http://dx.doi.org/10.1016/j.enpol.2015.10.047

Williams, E., Hittinger, E., Carvalho, R., & Williams, R. (2017). Wind power costs expected to decrease due to technological progress. *Energy Policy, 106*, pp. 427-435. doi:Wind power costs expected to decrease due to technological progress

Wind Energy Technologies Office. (2022). *How a wind turbine works - text version*. Retrieved April 2, 2022, from Energy.gov: https://www.energy.gov/eere/wind/how-wind-turbine-works-text-version

WindEurope. (2019). *Our energy, our future.* WindEurope. Retrieved from https://windeurope.org/about-wind/reports/our-energy-our-future/

WindEurope. (2020). *Offshore wind in Europe: Key trends and statistics 2020.* WindEurope. Retrieved from https://proceedings.windeurope.org/biplatform/rails/active_storage/disk/eyJfcmFpbHMiOnsibWVzc2FnZSI6IkJBaDdDRG9JYTJWNVNTSWhkV1J2ZFhoa1lXdDBOVEo1ZDI1MU1ETTBOMlpyTldSNWVtZHdkd1k2QmtWVU9oQmthWE53YjNOcGRHbHZia2tpQVpKcGJteHBibVU3SUdacGJHVnVZVzFsUFNKWGFXNWtSWFZ

WindEurope. (2022, May 18). *History of Europe's wind industry*. Retrieved 2022 May, from WindEurope: https://windeurope.org/about-wind/history/

Winslow, A. R. (2017). Urban Wind Generation: Comparing Horizontal and Vertical Axis Wind Turbines at Clark University in Worcester, Massachusetts. 127. Clark University. Retrieved from https://commons.clarku.edu/idce_masters_papers/127

Wiser, R., & Bolinger, M. (2019). *Benchmarking Anticipated Wind Project Lifetimes: Results from a Survey of U.S. Wind Industry Professionals.* Berkeley lab: Electricity markets & policy group. Retrieved from https://etapublications.lbl.gov/sites/default/files/wind_useful_life_report.pdf

Wiser, R., Bolinger, M., & Lantz, E. (2019). Benchmarking Wind Power Operating Costs in the United States: Results from a Survey of Wind Industry Experts. *Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory*. Retrieved from https://eta-publications.lbl.gov/sites/default/files/opex_paper_final.pdf

Xiaoni, W., & al., e. (2019). Foundations of offshore wind turbines: A review. *Renewable and Sustainable Energy Reviews*, 379-393. doi:https://doi.org/10.1016/j.rser.2019.01.012

Yan, R., & Zhang, Y. (2022, March 26). *The Introduction of NPV and IRR.* Atlantis Press International B.V. doi:https://doi.org/10.2991/aebmr.k.220307.241

Zhengru, R., Verma, A. S., Li, Y., Teuwen, J. J., & Jiang, Z. (2021). Offshore wind turbine operations and maintenance: A state-of-the-art review. *Renewable and Sustainable Energy Reviews, 144*. doi:https://doi.org/10.1016/j.rser.2021.110886

Ørsted. (n.d.). *Wind-technology*. Retrieved May 18, 2022, from Ørsted: https://orsted.com/en/our-business/offshore-wind/wind-technology

11. Appendix

11.1 A1 Costs literature overview

CAPEX literature overview

Reference	Parameter	Derived by	Value	Currency	Year	Region	Comment
Aldersey-Williams et al. (2019)	CAPEX	Audited accounts (SPV)	1500-2000	£/kW	2000-2010	UK	
Aldersey-Williams et al. (2019)	CAPEX	Audited accounts (SPV)	2000-4000	£/kW	2010-2020	UK	
IEA (2019)	CAPEX	Public domain sources, database	4353	$/kW	2018	Global	
IRENA (2019)	CAPEX	Public domain sources, database	4353	$/kW	2018	Global	
NVE (2022)	CAPEX	Public domain sources, database	2590	£/kW	2019	Norway	GBP/NOK 11,4794. 1400MW concept
BVG Associates (2019)	CAPEX	Public domain sources, database	2370	£/kW	2019-2025	UK	Cost breakdown 4 elements
IEA (2020)	CAPEX ex transmission costs	Public domain sources, database	2876	$/kW	2020	Global	23 projects in 8 countries
IRENA (2020)	CAPEX	Public domain sources, database	3185	$/kW	2020	Global	Driven by China deployment (50% of total in 2020)
Johnston et al. 2020	CAPEX	Public domain sources, database	4000	£/kW	2020	UK	Electricity generation costs
GWPF (2017)	CAPEX	Public domain sources	3200	£/kW	2020	Europe	
GWPF (2017)	CAPEX	Public domain sources	2770	£/kW	2021	UK	Estimate Triton Knoll +-140
GWPF (2017)	CAPEX	Public domain sources	2910	£/kW	2022	UK	Estimate Hornsea 2 +-160
GWPF (2017)	CAPEX	Public domain sources	3120	£/kW	2022	UK	Estimate Moray East +- 170
IEA (2019)	CAPEX	Public domain sources, database	2500	$/kW	2030	Global	
BEIS (2020)	CAPEX	Public domain sources, database	1430	£/kW	2030	UK	Economies of scale, turbine upsizing
NVE (2022)	CAPEX	Public domain sources, database	2226	£/kW	2030	Norway	GBP/NOK 11,4794. 1400MW concept
IRENA (2019)	CAPEX	Public domain sources, database	1700-3200	$/kW	2030	Global	
IEA (2019)	CAPEX	Public domain sources, database	1900	$/kW	2040	Global	
IRENA (2019)	CAPEX	Public domain sources, database	1400-2800	$/kW	2050	Global	

Table 11.1 *An overview of different historic and projected CAPEX values drawn from reports, journal articles and audited accounts. Source: authors own*

OPEX literature overview

Reference	Parameter	Derived by	Value	Currency	Year	Region	Comment
Ørsted (2015)	OPEX	Financial statement	118 000	$/MW/year	2015	NA	Reference from IRENA 2020
Aldersey-Williams et al. (2019)	OPEX	Audited accounts (SPV)	37	£/MWh	2017	UK	
Ørsted (2018)	OPEX	Financial statement	67 000	$/MW/year	2018	NA	Reference from IRENA 2020
IEA (2019)	OPEX	Public domain sources, database	90 000	$/MW/year	2018	Global	
IRENA (2021)	OPEX	Public domain sources, database	70 000-129 000	$/MW/year	2018	Global	(IEA et al., 2018; Ørsted, 2019; Stehly et al., 2018)
BEIS (2016)	Fixed O&M	Public domain sources, database	65 420	£/MW/year	2018	UK	Projection. Assuming 48% capacity factor
Hughes (2020)	OPEX	Audited accounts (SPV)	192 000	£/MW/year	2019	UK	Galloper wind farm
NVE (2022)	OPEX	Public domain sources, database	92 000	€/MW/year	2020	Norway	NOK/EUR 10,06
BVG Associates (2019)	OPEX	Public domain sources, database	75 000	£/MW/year	2019-2025	Europe	Mainly Europe. US and China not included
IEA (2020)	OPEX	Public domain sources, database	24,46	$/MWh	2020	Global	
Hornsea limited full accounts, 2020	OPEX	Audited accounts (SPV)	89 333	£/MW/year	2020	UK	Authors calculations
BEIS (2016)	OPEX	Public domain sources, database	59 915	£/MW/year	2020	UK	Projection. Assuming 48% capacity factor
BEIS (2020)	OPEX	Public domain sources, database	54 172	£/MW/year	2025	UK	Assuming 51% capacity factor
BEIS (2020)	OPEX	Public domain sources, database	48 000	£/MW/year	2030	UK	Assuming 57% capacity factor
NVE (2022)	OPEX	Public domain sources, database	69 980	€/MW/year	2030	Norway	NOK/EUR 10,06
IEA (2019)	OPEX	Public domain sources, database	60 000	$/MW/year	2030	Global	
BEIS (2020)	OPEX	Public domain sources, database	45 524	£/MW/year	2035	UK	Assuming 60% capacity factor
BEIS (2020)	OPEX	Public domain sources, database	44 576	£/MW/year	2040	UK	Assuming 63% capacity factor
IEA (2019)	OPEX	Public domain sources, database	50 000	$/MW/year	2040	Global	

Table 11.2 *An overview of different historic and projected OPEX values drawn from reports, journal articles and audited accounts*

LCOE literature overview

Reference	Parameter	Derived by	Value	Currency	Year	Region	Comment
Aldersey-Williams (2019)	LCOE	Audited accounts	66,4-158,7	£/mWh	2003-2010	UK	Historic actual
Aldersey-Williams (2019)	LCOE	Audited accounts	72,1-179	£/mWh	2010-2017	UK	Historic actual / projections
IEA (2019)	LCOE	Public domain sources, database	140	$/mWh	2018	Global	8% WACC
IRENA (2019)	LCOE	Public domain sources, database	130	$/mWh	2018	Global	
NVE (2021)	LCOE	Public domain sources, database	78	€/mWh	2020	Norway	1400MW project. 6% WACC
NVE (2022)	LCOE	Public domain sources, database	69,4	€/mWh	2021	Norway	1400MW project. 6% WACC
Greenstat (2021)	LCOE	Public domain sources, database	51	€/mWh	2021	Norway	1400MW project. 6% WACC
BEIS (2020)	LCOE	Public domain sources, database	57	£/mWh	2025	UK	Projections
NVE (2022)	LCOE	Public domain sources, database	53,9	€/mWh	2030	Norway	1400MW project. 6% WACC
NVE (2021)	LCOE	Public domain sources, database	60	€/mWh	2030	Norway	1400MW project. 6% WACC
IEA (2019)	LCOE	Public domain sources, database	90	$/mWh	2030	Global	8% WACC
IRENA (2019)	LCOE	Public domain sources, database	50-90	$/mWh	2030	Global	
IEA (2019)	LCOE	Public domain sources, database	60	$/mWh	2040	Global	8% WACC
IRENA (2019)	LCOE	Public domain sources, database	30-70	$/mWh	2050	Global	

Table 11.3 *An overview of different historic and projected LCOE values drawn from reports, journal articles and audited accounts*

11.2 A2 - Calculations made in excel

Year	Annual output	Gross revenue	Variable OPEX	Net revenue	Fixed OPEX	EBITDA	Depreciation	Taxable profit	Corp tax	Post-tax profit	DECOM	Project debt payments	Project debt interest	Project cash flow
	MWh	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW	NOK000 /MW
0														-9889,0
1	5 908	1881,3	154,2	1727,0	678,0	1049,0	1977,8	-1967,1	0,0	-1967,1		0,0	1038,3	10,7
2	5 400	1768,2	252,3	1515,9	678,0	837,9	1977,8	-2178,2	0,0	-2178,2		1483,3	1038,3	-1683,8
3	5 870	2671,1	261,8	2409,3	678,0	1731,3	1977,8	-1232,9	0,0	-1232,9		1483,3	986,4	-738,5
4	5 859	2665,7	207,0	2458,8	678,0	1780,8	1977,8	-1131,5	0,0	-1131,5		1483,3	934,5	-637,1
5	5 624	2763,2	168,8	2594,3	678,0	1916,3	1977,8	-944,1	0,0	-944,1		1483,3	882,6	-449,6
6	5 152	2233,4	230,2	2003,2	678,0	1325,2	1977,8	-1483,3	0,0	-1483,3		1483,3	830,7	-988,8
7	6 091	2745,9	220,0	2525,9	678,0	1847,9	1977,8	-908,7	0,0	-908,7		1483,3	778,8	-414,2
8	5 524	2865,3	332,8	2532,5	678,0	1854,5	1977,8	-850,1	0,0	-850,1		1483,3	726,8	-355,7
9	5 266	2444,7	187,0	2257,7	678,0	1579,7	1977,8	-1073,0	0,0	-1073,0		1483,3	674,9	-578,6
10	5 234	2279,6	276,0	2003,6	678,0	1325,6	1977,8	-1275,2	0,0	-1275,2		1483,3	623,0	-780,8
11	5 407	2730,6	240,0	2490,6	678,0	1812,6	1977,8	-736,3	0,0	-736,3		1483,3	571,1	-241,8
12	5 501	2680,4	194,1	2486,3	678,0	1808,3	1977,8	-688,7	0,0	-688,7		1483,3	519,2	-194,2
13	5 073	2657,7	57,7	2600,0	678,0	1922,0	1977,8	-523,1	0,0	-523,1		1483,3	467,3	-28,6
14	5 505	2591,3	263,5	2327,8	678,0	1649,7	1977,8	-743,4	0,0	-743,4		1483,3	415,3	-248,9
15	6 030	3012,7	229,4	2783,3	678,0	2105,2	1977,8	-236,0	0,0	-236,0		1483,3	363,4	258,5
16	5 209	3082,6	165,1	2917,5	678,0	2239,5	1977,8	-49,8	0,0	-49,8		1483,3	311,5	444,6
17	5 322	2797,1	184,7	2612,4	678,0	1934,4	1977,8	-303,0	0,0	-303,0		1483,3	259,6	191,4
18	5 561	3413,7	316,2	3097,5	678,0	2419,5	1977,8	234,0	0,0	234,0		1483,3	207,7	728,5
19	5 178	2753,0	202,5	2550,4	678,0	1872,4	1977,8	-261,1	0,0	-261,1		1483,3	155,8	233,3
20	5 993	2359,9	249,0	2110,8	678,0	1432,8	1977,8	-648,8	0,0	-648,8		1483,3	103,8	-154,4
21	5 317	3064,5	238,6	2826,0	678,0	2148,0	0,0	2096,0	0,0	2096,0		1483,3	51,9	612,7
22	5 262	3447,0	293,4	3153,6	678,0	2475,5	0,0	2475,5	0,0	2475,5		0,0	0,0	2475,5
23	5 944	3679,4	276,5	3402,9	678,0	2724,9	0,0	2724,9	0,0	2724,9		0,0	0,0	2724,9
24	5 429	3219,7	170,5	3049,2	678,0	2371,2	0,0	2371,2	0,0	2371,2		0,0	0,0	2371,2
25	5 403	3479,3	232,3	3247,0	678,0	2569,0	0,0	2569,0	0,0	2569,0		0,0	0,0	2569,0
26	0	0,0	0,0	0,0	678,0	-678,0	0,0				2796,5	0,0		-3474,6
Present Value per MW in NOK000														**-12520,5**
Total PV for 1400 MW project in NOK million														**-17528,7**

Table 11.4 *Illustrated project values for 1 simulation in the base case scenario for SNII. The negative CF in year 0 represent the 25% equity investment. The project cash flow to the right is discounted to obtain the net present value per MW. This value is further multiplied with the farm capacity. Source: authors own.*