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An analysis on the attractiveness of different grid configurations for offshore wind power investors

A real-options approach to analyse the investment incentive for investors in offshore wind power under different grid configurations

Vegard Hågård Hoch-Nielsen
Renewable Energy

Preface

This thesis marks the end of a two-year master's degree in Renewable Energy at the Norwegian University of Life Sciences (NMBU).

My interest in renewable energy and business has been a big part of my studies, and in this thesis, I got to combine my interest by researching investments in offshore wind power. Throughout these last five months I have learned a lot about offshore wind and how to develop an investment decision model, and I am looking forward to working in this field in the future.

As this thesis marks the end of my studies, I would like to thank several people. A special thank you to my supervisor Kristin Linnerud for your guidance and inspiration throughout this process. I also want to thank my friends and family for your continuous support throughout my years of study.

Vegard Hågård Hoch-Nielsen
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Abstract

Attracting offshore wind power investors is important for the Norwegian government to reach its development goal for offshore wind power. This thesis presents an investment decision model to evaluate the investment incentive in offshore wind farms and hybrid projects under various grid configurations. Using a real-options approach, based on a binomial lattice method that embeds deferral options, the model derives the investment incentive and the optimal investment timing for investors in an uncertain environment. The results show that the grid configuration has a significant impact on the investors investment incentive. A three-market hybrid configuration is generally preferred over a radial connection to Norway and a two-market hybrid by offshore wind power investors. I find that the offshore wind farm is more profitable in a hybrid configuration when it is connected to markets with higher prices than NO2, low price volatility, and a positive correlation with NO2. Under a historic electricity price level, the results suggests that subsidies are necessary to attract investors. However, using a simulated future electricity price level, offshore wind farm can become viable without subsidies. Additionally, the results show that a hybrid configuration does not necessarily reduce the offshore wind power project's risk. Moreover, investors and regulators preference in grid configuration are partially aligned. A two-market hybrid is undesirable for wind farm investors but preferred by regulators, but both find a three-market hybrid configuration desirable. The conclusion of this thesis can provide useful guidelines for policy makers determining grid configuration, as this decision affect investment incentive for offshore wind power investors and the socio-economic benefit from offshore wind development.

Sammendrag

Å tiltrekke seg investorer til å investere i havvind er viktig for at den norske regjeringen skal oppnå målet sitt for utbygging av havvind. Denne masteroppgaven presenterer en investeringsbeslutningsmodell til å evaluere insentivet til å investere i havvind- og hybridprosjekter i ulike kraftnettverkskonfigurasjoner. Ved å bruke en real-opsjons tilnærming basert på en binær rutenettmetode som innehar utsettelsesopsjoner, har modellen som mål å utlede insentivet til å investere og optimal timing for å investere i havvind under usikre omstendigheter. Resultatene viser at valg av kraftnettkonfigurasjon har betydelig innvirkning på investorenes investeringsincentiv. En hybrid nettkonfigurasjon med tre markeder foretrekkes generelt fremfor en radiell tilkobling til Norge og en hybrid med to markeder av havvindinvestorer. Havvindparker i en hybrid nettkonfigurasjon er lønnsommere dersom den er tilknyttet markeder med høyere priser enn NO2, lav prisvolatilitet og har en positiv korrelasjon med NO2. Under et historisk strømprisnivå viser resultatene at subsidier er nødvendig for å tiltrekke investorer, men at havvindparker kan bli levedyktig uten subsidier ved en høyere fremtidig strømpris. Videre viser resultatene at en hybrid nettkonfigurasjon ikke nødvendigvis reduserer risikoen til havvindprosjektet. Investorenes og myndighetenes preferanser for nettverkskonfigurasjon er delvis sammenfallende. En hybrid med to markeder er uønsket av investorer, men foretrukket av myndighetene, mens begge finner en hybrid konfigurasjon med tre markeder attraktiv. Konklusjonen i denne masteroppgaven kan gi nyttige retningslinjer for myndigheter som bestemmer nettverkskonfigurasjonen, da denne beslutningen påvirker investeringsinsentiver for havvindutbyggere og den samfunnsøkonomiske nytten fra havvind.

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1 Introduction

1.1 Rationale and actualization

The ongoing process of industrialization and the rapid growth of the global economy have resulted in a steady rise in the consumption of traditional energy sources. This, in turn, has caused increased CO_2 emissions causing climate change. The awareness of climate change's impact and risk has enhanced joint actions by nations globally, leading to ambitious energy and climate targets to address the challenge. Offshore wind energy is anticipated to play a critical role in accelerating the transition towards sustainable practices by providing a renewable energy source.

It is projected by IEA (2019) that offshore wind energy will contribute significantly to Europe's electricity generation, being the largest electricity source by 2040. The European Commission (2020) is in the forefront of tackling climate change, and put forward an ambition of 60 and 300 GW installed offshore wind capacity by 2030 and 2050, respectively. According to Wind Europe (2022) by June 2022 the installed capacity in the EU was 28,4 GW, and in the beginning of 2023 the European Commission (2023) agreed on raising the target from 60 to 111 GW installed capacity by 2030. The European Commission (2023) also agreed on proposing an integrated offshore network to incorporate the large expected amount of offshore wind generation.

In May 2022 the Norwegian Government (2022) set a goal of 30 GW installed offshore wind capacity by 2040, which is equivalent to the total installed capacity in Norway at present. The Norwegian Government perceives offshore wind as a solution to meet the mounting electricity demand and an opportunity for new industry, enabling future economic growth and employment opportunities. Due to the extensive wind resources along Norway's coastline and expertise in maritime and petroleum industry, Norway has a privileged position to take part in the emerging offshore wind power market (Meld. St. 36 (2020–2021)). In June 2020 the Norwegian government opened two areas for offshore wind production in Sørlige Nordsjø II (SNII) and Utsira Nord. According to Statnett (2022b) the Norwegian power balance can reach a deficit by 2027 as the projected demand for electricity increases by 24 TWh, but whereas the supply side only increases by 6 TWh. After 2027, Statnett estimates that the electricity balance will return towards unity as they expect offshore wind to enter the market.

In light of the past years increase in the Norwegian electricity prices, planned overseas transmission cables between Norway and high-priced European countries are debated (Lydersen et al., 2021). This has also prompted discussions regarding whether the offshore wind generation from SNII should be brought directly to the onshore grid of Norway or if some of the electricity also should be exported to a foreign market. Due to the strategic positioning of SNII, being in close proximity to other North Sea nations, the possibility of supplying power to the European energy market may be technically and financially feasible. The overseas transmission cables connect Norway, with historically low and stable electricity prices to Europe's electricity market, who has had historically higher and more variable prices. The resulting electricity flow is therefore mostly out of Norway, increasing the Norwegian power price. The Norwegian government thereby announced to halt all plans of overseas transmission cables in 2021, except for offshore wind (Holter et al., 2021). The latest spike in natural gas prices due to the Russian invasion of Ukraine in the spring of 2022 and low precipitation in Norway caused further unprecedented high electricity prices in Europe and Norway the last year. The Norwegian government then announced that SNII will be auctioned in two phases, with the first phase of 1500 MW only being connected to Norway. The specific grid configuration for phase 2 of SNII has not yet been determined (Minestry of Petroleum and Energy, 2023; Minestry of Petroleum and Energy, n.d.).

A direct linkage between the wind farm and the onshore grid of Norway is referred to as a radial connection, while a hybrid project combines offshore power generation with transmission capacity connecting two or more markets. When the offshore wind power (OWP) generation is lower than the capacity of the cable, the hybrid connection allows for trade between the markets and thereby optimizing the dispatch of electricity and increasing efficiency (THEMA, 2020). According Gorenstein Dedecca and Hakvoort (2016) several studies have shown economic and non-monetary benefits from a hybrid project in the North Sea due to efficient dispatch, increased system flexibility and reliability. Although, for an offshore wind farm connected to a hybrid grid, the market designs have an impact on what price the OWP developer receives (Kitzing & Schröder, 2012). According to RME (2023) the preferred market design under a hybrid project is the offshore bidding zone design (OBZ). In the OBZ market design the offshore wind farm may be adversely affected which consequently can reduce the OWP investors willingness to invest (ENTSO-E, 2020; THEMA, 2020). Therefore, the incentive for establishing a hybrid grid from an OWP investor and social planner's perspective, referred to as a regulator in this thesis, may not be aligned.

During prior discussions, industry experts have contended that the implementation of hybrid projects is essential for the offshore wind project to achieve financial viability. Various solutions have been proposed, including the developer assuming responsibility for constructing and owning the hybrid project. It has also been suggested that the transmission system operator (TSO) should own and build the hybrid project, provided that the OWP developer obtains a reasonable electricity price, or a support scheme that allows for reallocation of congestion income obtained from electricity trading between markets. The proposed solutions have been evaluated in reports by THEMA (2020) and RME (2023) which finds them infeasible. This thesis is motivated by the absence of market designs that favour OWP developers. Therefore, the objective is to investigate the incentive to invest in offshore wind power projects within the current proposed market design, without a support scheme.

Previous research on the economic impacts of grid configurations has to a large degree restricted its attention to socio-economic implications. Taking the regulators perspective, Houghton et al. (2016), Gorenstein Dedecca and Hakvoort (2016) and Spro et al. (2015) investigates the impact of hybrid grids, finding them socio-economic beneficial. From a regulators perspective the socio-economic benefit of the project is important. However, a paper by Kitzing and Schröder (2012) analyses grid configurations from both an offshore wind power developers' and TSO's perspective using a real-options approach. They find that both market design and grid configuration have a significant impact on the investment incentive for the OWP developer and TSO. Similarly, this thesis investigates the investment incentives for OWP developers under multiple grid configurations, using a real-options approach. This thesis addresses a research gap in this area by using parameters based on historical data from onshore bidding zones and use a more detailed modelling of the offshore wind farm's cash flow, to assess the profitability, project risk and optimal investment timing for OWP investors. Additionally, by considering the investment in both the offshore wind farm and grid, referred to as the hybrid project, this thesis investigates the alignment of preferences in grid configuration between the OWP investor and regulator.

1.2 Research question and objectives

The objective of this thesis is to assess the investment incentive in offshore wind power and hybrid projects under various grid configurations. More specifically, I determine the profitability of a OWP and a hybrid project with a real-option approach using a binomial lattice method with defer options embedded, under a radial grid connected to Norway and hybrid grids between Norway and one or two other countries in the North Sea region. The research question that this thesis attempts to answer is:

How do different grid configurations impact the investment incentive in offshore wind power and hybrid projects?

To support the main question, four sub objectives have been formulated to direct and focus the study. Sub objectives one to three analyses the objective from an investor perspective and a regulator's perspective and objective four is a comparative analysis. The OWP and hybrid project investigated are located in Sørlige Nordsjø II under the offshore bidding zone market design. The sub objectives are as follows:

RO1: Identify the project's *profitability* in a radial, two-market and three-market hybrid grid using a real options approach.

RO2: Identify the project's *risk* in a radial, two-market and three-market hybrid grid using a real options approach.

RO3: Identify the project's optimal investment *timing* in a radial, two-market and three-market hybrid grid using a real options approach.

RO4: Identify if the grid preferences of OWP investors and regulators are aligned.

1.3 Scope and delimitation

To clarify the essence of this thesis, the present subchapter will define the scope and boundaries and what implications these have.

The objective of this thesis is to investigate the profitability, riskiness, and optimal investment timing and of a OWP and hybrid project located in Sørlige Nordsjø II under the different potential grid configurations such as a radial, two-market and three-market hybrid grid. As previously noted, under a hybrid grid configuration, the preferred market design is the offshore bidding zone (OBZ) design, and it is therefore used in this analysis. Other market designs are not analysed in this thesis.

The wind farm situated in SNII can be linked to various countries surrounding the North Sea area whereas this thesis restricts its analysis to include Norway (NO2), Denmark (DK1), Great Britain, and Germany. In every grid configuration, a connection to the Norwegian bidding zone NO2 is used (NVE, 2023; Statnett, 2022a). The historical electricity price patterns in Norway, Denmark, Great Britain, and Germany are different due to their distinct electricity mixes and consumption characteristics. Consequently, the electricity price received by an offshore wind farm is influenced by both the grid configuration and what markets are connected to the grid.

At present, some details pertaining to the offshore wind farm and grid configurations remain undecided. However, it is probable as discussed in RME (2023) that for a radial grid design to Norway the OWP developer finances the OWP project and pay the TSO a construction payment for facilitating a transmission cable to the Norwegian shore. In this case the investment incentive of the project will be equivalent from the perspective of the investor and regulator. In the case of a hybrid grid, the developer will finance the OWP project and serve a construction payment to the TSO equal to investment cost of the radial grid (RME, 2023). In this case the TSO builds the transmission cable(s) connecting the other market(s) and receive congestion income from electricity trade. In this case the investment incentive from the regulator’s perspective includes both the investments made by both the OWP developer and TSO which is called the hybrid project.

From the regulators perspective this thesis limits its inquiry to the assessment to the hybrid project. Other economic factors including potential price effects in connected markets, due to increased electricity generation and trade, as well as non-economic considerations is outside the scope of this thesis. Additionally, I do not account for the allocation of ownership of the transmission cables between the respective TSO’s in the connected countries.

The analysis uses parameters based on historical data and projections in the base case scenario and performs an analysis on a scenario with simulated future electricity prices, based on assumptions for the future energy mix. In general, it should be noted that the conditions under which this analysis is conducted may not represent the future electricity market, and projections are inherently uncertain. The modelling methodology employed in this study constrains the ability to simulate future prices on an hourly basis and subsequently model the OBZ price through price formation. Consequently, the future OBZ price in each grid configuration is established based on hourly historical price data in connected markets, using a hypothetical OBZ. Although this possibility is limited, this thesis will investigate future assumptions on price and volatility in the historically formed OBZ price. Therefore, this thesis focuses primarily on historical market characteristics and to decipher factors than can be generalized.

1.4 Clarification of concepts

Radial grid: A radial grid serves the purpose of transporting offshore wind generation ashore. A radial grid is synonymous with purely connecting the offshore farm to Norway as this is the only radial connection analysed in this thesis.

Hybrid project/grid: A hybrid project includes offshore wind generation and transmission capacity between two or more onshore bidding zones. The hybrid grid connects the offshore generation to two or more onshore bidding zones and serves a dual functionality of transporting the offshore electricity generation ashore and it allows for trade between the onshore markets.

Congestion income: Congestion income is the income received by the grid owner from trade between bidding zones. A transmission cable between two market with different prices allows the owner of the transmission cable to buy electricity in the low-priced market, and then sell the electricity to the higher priced market, thereby making a profit.

1.5 Structure of the thesis

The rest of this thesis is structured as follows: Chapter two presents literature on the real-options approach being applied to investments in offshore wind, and literature on offshore grid configurations. Chapter three outlines the case of Sørlige Nordsjø II, which this thesis applies its model to. Chapter four outlines the relevant theory, model design and describes the data collected. Chapter five presents the results of the analysis, chapter six discuss the results and implications, before the conclusion is drawn in chapter seven.

2 Literature review

This chapter provides a review of the relevant literature related to the research question asked in this thesis. Firstly, the literature on offshore wind investments with the real options approach is outlined. Thereafter, I present literature researching grid configurations and market design for offshore wind and hybrid projects.

2.1 Real options approach to offshore wind power

Real options are only valuable when there is uncertainty, and for this reason it is an important task in the methodology to identify sources of uncertainty in offshore wind power projects. Several studies have identified various risk factors associated with offshore wind energy using a real-options approach (ROA). Iniesta and Barroso (2015) highlights that offshore wind projects are subject to numerous uncertain factors, such as cost, technical uncertainty, and the regulatory environment. Offshore projects are generally more expensive than onshore projects and since offshore wind technology is immature, the regulatory environment can be more complex. Technological uncertainty in OWP is heavily emphasized by Schwanitz and Wierling (2016), particularly related to foundation design, turbine performance and cable installation. They also find that offshore wind investments cost has developed contrary to optimistic expectations and that it is not certain that offshore wind investments cost will decrease in the future, due to an increasing complexity and high uncertainty related to the immature offshore wind technology. Wind speed and the electricity price is found to be an important factor by Gazheli and van den Bergh (2018) and Kitzing et al. (2017) in determining the revenue of a OWP, and notes that the wind speed and electricity price variability can increase project risk and affect the economic feasibility. Therefore, in an uncertain environment a real-options approach is more appropriate than traditional cash flow methods for evaluating OWP projects (Liu et al., 2021b).

A number of studies have contributed to the field of applying a ROA to the field of offshore wind power investments. Li et al. (2019) introduces a real options model to investigate the investment benefit for an OWP investor under a market co-movement effect. They account for uncertainties including investment cost, feed-in-tariffs, carbon prices, and policy subsidies. The model is applied to a case, using a least-squares Monte-Carlo simulations to find project value and to determine if investors should abandon or postpone the investment. Climate change uncertainty was include the ROA by Kim et al. (2018). They proposed a decision-making model than considers the impacts of climate change to analyse the feasibility of offshore wind farms. More specifically, they consider the project volatility using wind speed projections derived from climate scenarios and solves the option values using a binomial lattice. They find that the managerial flexibility in the real-options approach reduces risk and increase long-term profitability of OWP projects. Kitzing et al. (2017) applied a general real option model to a OWP project in the Baltic Sea, considering the optimal investment timing and capacity sizing to study the investment incentive under three support schemes. The power price and wind speed are modelled as uncertain factors and the analysis provide a closed-form solution. Closes to this thesis research topic, Kitzing and Schröder (2012) used a ROA to investigate the investment incentive of OWP investors and the TSO in different market and grid configurations. They modelled the electricity price as a geometric Brownian motion (GBM) and used Monte Carlo simulations to account for uncertainty and solve the option value.

According to Schwartz (2013) it exists three main solution methods for solving real option valuation problems: dynamic programming, partial differential equations and simulation approach. Whereas the binomial method is widely used to value simple options, and it can be used to value American-type options. Previous research applying the ROA with a binomial lattice to investments are papers by Fan et al. (2013) who evaluated investments in coal bed methane, Wang and Du (2016) who expands the binomial lattice to a quadrinomial model to evaluate investments in carbon capture and storage and Zhang et al. (2014) proposing a model to evaluate the policies applicable to investments in solar PVs. Closest to this thesis, methodically, Liu et al. (2021a) proposes an investment decision framework for OWP investors using a ROA and a bidimensional binomial lattice that embeds deferral options. The paper analyses the OWP project's profitability and the appropriate development timing under three subsidy schemes. The electricity price and carbon price are represented by a GBM and modelled in is discrete form represented as a binomial lattice stochastic process. Moreover, the initial investment cost is modelled as an uncertain technical variable implementing the learning-by-doing (LBD) curve. Their findings show that it is preferable to defer the investment in the absence of subsidies and finds the subsidy amount required to render the project profitable.

2.2 Grid and market designs for offshore wind power

Recently, several studies are conducted on the technical, and economic aspects of offshore wind power and grids. The technical aspects of offshore grid solutions was analysed by Trötscher and Korpås (2011) who identified the optimal transnational offshore high voltage direct current (HVDC) grid structure in the North Sea, for the integration of large amounts of OWP generation. Other technical aspect was investigated by Sedighi et al. (2016) who determined the optimal electrical interconnection configuration for OWP for a given topology and number of turbines and Apostolaki-Iosifidou et al. (2019) who assessed how offshore wind generation can be brought ashore. Elahidoost and Tedeschi (2017) review the proposed approaches for HVDC grid expansion in the North Sea, outlining how strategies and tools should be modified to properly include HVDC technology. However, in this thesis the economical assessments of grid configurations are in focus, with a primary view on the financial impact different grid configurations has for the OWP investor.

From an economic point of view Schröder et al. (2010) analyse four offshore grid networks relevant to the planned Krieger Flak wind park located in the Baltic Sea. The location was feasible for combining the OWP generation in the Swedish, German, and Danish zone through an offshore node. Their primary research was focused on deriving the possible congestion rent and quantify the change in power prices in markets neighbouring Krieger's Flak under an offshore node. Their analysis show that the grid configuration has a strong impact on the congestion income received by the grid owner, and on the income of the OWP investor. In conclusion they find that a common offshore node can be beneficial.

Schröder (2013) investigates the market design and capacity allocation regimes on the economics of offshore wind farms and transmission grid operators. They investigate a radial connection, a hybrid configuration where the offshore wind farm is incorporated into one country's bidding zone, and a hybrid configuration as a separate offshore bidding zone. They find that capacity allocation regimes have strong consequences for offshore wind operators and the TSO. Moreover, they show that when establishing an offshore bidding zone, the question of whether the OWP developer should receive the higher or lower neighbouring price occurs. The offshore wind farm operator will have less income when receiving the lowest of the neighbouring market prices compared to the highest market price, whereas the TSOs revenue increases by the same amount. Schröder et al. (2010) and Schröder (2013) analyse the congestion income and socio-economic benefits, as opposed to investment incentive for OWP developers which is the main focus of this thesis.

Kitzing and Schröder (2012) do however analyse how OWP investors and TSO are affected by market design and grid configurations. They employ a real-options approach to investigate how the OWP investors and TSOs are affected in grid configurations between one, two, three, and four onshore bidding zones, under the market designs “Home country”, “Primary access” and “Offshore hub”. The offshore hub market design is equivalent to what is referred to as the offshore bidding zone (OBZ) in this thesis. They find that the OWP project’s expected internal rate of return (IRR) in the OBZ design is the lowest for a two-market hybrid and the highest in a radial configuration, with the three-market and four-market hybrid being second and third most desirable, respectively. Moreover, their analysis shows that there is a reduced variation in IRR for each additional country connected to the OBZ, thereby reducing project risk. From the TSOs perspective, the congestion revenue increases for each country connected. Kitzing and Schröder (2012) highlights the opposing interest of OWP developers and the TSO, arguing it can hamper the development of an offshore hub. This thesis contribution to the literature on this topic and fills the research gap as noted in the work by Kitzing and Schröder (2012), by analysing the market design and grid configurations impact on OWP investors and regulators using real-word data which I apply to the case of Sørlige Nordsjø II.

3 Case description – Sørlige Nordsjø II

This chapter presents the planned development of offshore wind power projects in the Sørlige Nordsjø II region. I firstly present background information and the characteristics of Sørlige Nordsjø II. Thereafter, I explain the market design, grid configurations and price formation which is relevant to understanding what electricity price an offshore wind farm receive under different grid configurations. Additionally, the congestion income received by a hybrid project is outlined.

3.1 Sørlige Nordsjø phase I and II

Sørlige Nordsjø II (SNII) is suitable for offshore wind power located approximately 200-250 km off the Norwegian coast close to the economic zone of Denmark. The area is interesting for OWP as it benefits from strong wind conditions with an expected capacity factor of approximately 55% which corresponds to about 4 900 full-load operating hours. For comparison, larger land based wind farms in Southwest Norway has a capacity factor of about 40% (NVE, 2023). With an average water depth of 60 meters, the location is suitable for both floating and bottom-fixed offshore wind technology. Although, SNII is intended for bottom-fix, as the floating technology is more expensive and will require higher subsidies. Moreover, Utsira Nord was opened for OWP at the same time as SNII and with a water depths of 220-280 floating OWP is the only suitable technology (Statnett, 2022a).

In January 2022, the Norwegian government announced that offshore wind projects at SNII will be developed in two phases, with the first phase connected to Norway through a radial connection. Each phase constitutes a generation capacity of 1,500 MW, which is equivalent to around 6 TWh in a low production year and 7,4 TWh in a high producing year. This initial build-out is intended to increase power supply to southern Norway to meet the increasing demand, as it is projected that Norway may experience power deficits as early as 2027 (Statnett, 2022b). The construction of the initial 1500 MW of offshore wind power in SNII is planned to commence during the latter half of the 2020 decade. The allocation of licenses for the initial phase of Sørlige Nordsjø II will be carried out through a price auction in the end of 2023, where eligible consortia can participate to secure the license. The Norwegian government intends to award the license through a contract for difference (CfD) support scheme, where the entity submitting the lowest bid will be granted the license (Norwegian Government, 2023). The CfD support scheme guarantees the OWP owner the contracted electricity price, which is determined by competitive bidding between the eligible entities. The scheme is designed to minimize the level of support through competitive bidding and the contracted electricity price rises the OWP willingness to invest by guaranteeing an income and reducing risk. It is not determined if phase II will be awarded through a support scheme, and therefore this thesis limits its scope to investigate if the market prices alone are sufficient to render OWP project profitable.

For the second phase of the development, it has not yet been determined how the remaining 1500 MW will be connected. The location of Sørlige Nordsjø II presents the possibility for a hybrid connection between Norway and one or more additional countries as for example Denmark, Great Britain, Germany, and The Netherlands. Due to the long distance away from the shore and the high amount of power, high voltage direct current (HVDC) technology will be employed for power transmission from SNII to the onshore grid of Norway and other potential markets. HVDC is the same technology used in overseas power transmission cables to neighbouring countries today. Statnett (2022a) outline future possible connections and notes that if a radial connection is chosen at first, it can be expanded to a hybrid solution or part of a meshed network, but technical choices supporting such an expansion must be made in the first construction phase. This thesis does not investigate the possibility of extending a radial grid to a hybrid at a later stage, but assumes it is either built a radial or hybrid grid.

In pursuit of the Norwegian governments goal to reach 30 GW of offshore wind power production by 2040, the Norwegian government aims to open multiple areas for offshore wind generation. According to NVE (2023) if Norway is to have a major initiative and development of offshore wind power, there are many areas where a radial connection to the shore is the only possible grid solution, particularly in the northern parts of Norway. However, the Norwegian electricity grid is not equipped to entirely incorporated 30 GW of offshore wind power production in its current form. If larger volumes of offshore wind power are to be developed in Norway, it is probable that a considerable proportion of the production will have to be exported. Given its favourable geographical location within the North Sea, Sørlige Nordsjø II represents a prime candidate for a hybrid grid solution, which should be assessed as part of the evaluation of grid options for phase 2 of the SNII project.

3.2 Grid configuration and market design for Sørlige Nordsjø II phase 2

The market design is an important determinant of the price which offshore wind power producers are able to sell their electricity. A radial connection offers a simple market structure for the OWP project, as the project will receive the price in the market to which it is connected. For a hybrid grid Roland Berger (2019) proposed four market setups for integrating hybrid projects into the European electricity market. However, NSWPH (2020) evaluated these market setups and find that two are incompatible with requirements specified in the Capacity Allocation and Congestion Management Guideline, as set out by the European Union. ENTSO-E (2020) reviewed the two remaining concepts for market design, which is the Home Market (HM) and the Offshore Bidding Zone (OBZ).

HM: In the HM design the offshore wind farm participates in its home market by submitting bids and receives the home market electricity price regardless of the price in the other markets. The cable linking the wind farm's hub to the home market is considered a hybrid asset, while the cables connecting the hub to the other bidding zone(s) are considered a cross-border interconnection.

OBZ: In the OBZ design the offshore hub is formed as a distinct bidding zone, where the offshore wind farm submits its bids and are dispatched accordingly. Through market coupling, offshore generation is matched with onshore demand, and the resulting electricity price within the OBZ is equivalent to the price in the market connected with an uncongested transmission cable to the OBZ. What market has the uncongested transmission cable depends on the OWP generation and the grid configuration, which will be outlined in the following paragraphs.

In their report ENTSO-E (2020) concludes that the OBZ market design appears to be a promising solution, as it ensures market and system operation efficiency through competition, reflects limitations on the grid, gives correct price signals and is compliant with existing requirements. However, ENTSO-E and Kitzing et al. (2017) notes that the OBZ design could have an negative impact on the revenues for OWP projects connected to a hybrid grid compared to the HM design.

In the OBZ, the grid configuration and capacity on the also cables affects the price which the OWP developer receives (Kitzing et al., 2017). Reports by Statnett (2022a) and NVE (2023) have conducted analyses of possible grid designs for SNII under the OBZ market design. Statnett evaluates grid solutions for both phase 1 and 2, whereas NVE focused solely on phase 2. Statnett's evaluation involved exploring three hybrid concepts, namely a large, a small, and an asymmetric hybrid connection, all designed with a total of 3000 MW installed capacity of offshore wind in mind. The large hybrid design featured 2800 MW capacity to both the NO2 and a foreign market, while the small hybrid offered 1400 MW capacity to both markets. The asymmetric hybrid allocated 2800 MW to the NO2 and 1400 MW to the foreign market. However, as phase 1 is to be built with a radial grid, the capacities evaluated by Statnett are not entirely applicable. Nevertheless, NVE's report analysed four similar concepts in addition to a radial connection: a small, a large, and two asymmetric hybrid concepts, one featuring a larger capacity to the NO2 and the other to the foreign market. The small hybrid had a capacity of 700 MW to each market, the large hybrid 1400 MW to each market, while the asymmetric concepts allocated 1400 MW to one market and 700 MW to the other. In Figure 1 an illustration of a radial to NO2 (top left), a large two-market hybrid project between NO2 and country B (top right), a large three-market hybrid between NO2, country B and C (bottom left) and an asymmetric two-market hybrid between NO2 and country B (bottom right) is displayed.

Both market design and grid configuration affect the prices which the offshore wind farm receives. In the HM market design, the OWP developer receives the NO2 price unconditionally. For a large two-market hybrid the OBZ price will always equal the lowest of the two markets connected. For example, the OWP generation is 1 000 MW, and flows towards the high-priced market. The capacity on each cable is 1 400 MW, and the remaining 400 MW capacity is used for power exchange from the low-priced market to the high-priced market. In this case, the electricity flow is 1400 MW from the OBZ to the high-priced market, and 400 MW from the low-priced market to the OBZ. Thereby, the uncongested transmission cable is between the OBZ and the low-priced market, which determines the OBZ price. As a result, the OWP project linked to the OBZ will on average receive a lower electricity price compared to a radial grid connection to the low-priced market, if the two markets are taking turns begin the lowest-priced market. In an asymmetrical two-market hybrid, the price is mostly equal to the lowest priced market, but it may depend on the OWP generation and on whether the largest capacity is to the low- or high-priced market.

For a three-market hybrid the OBZ takes the price of the median priced market. Using the same example, the OWP generation of 1000 MW flows to the high-priced market. The low-priced

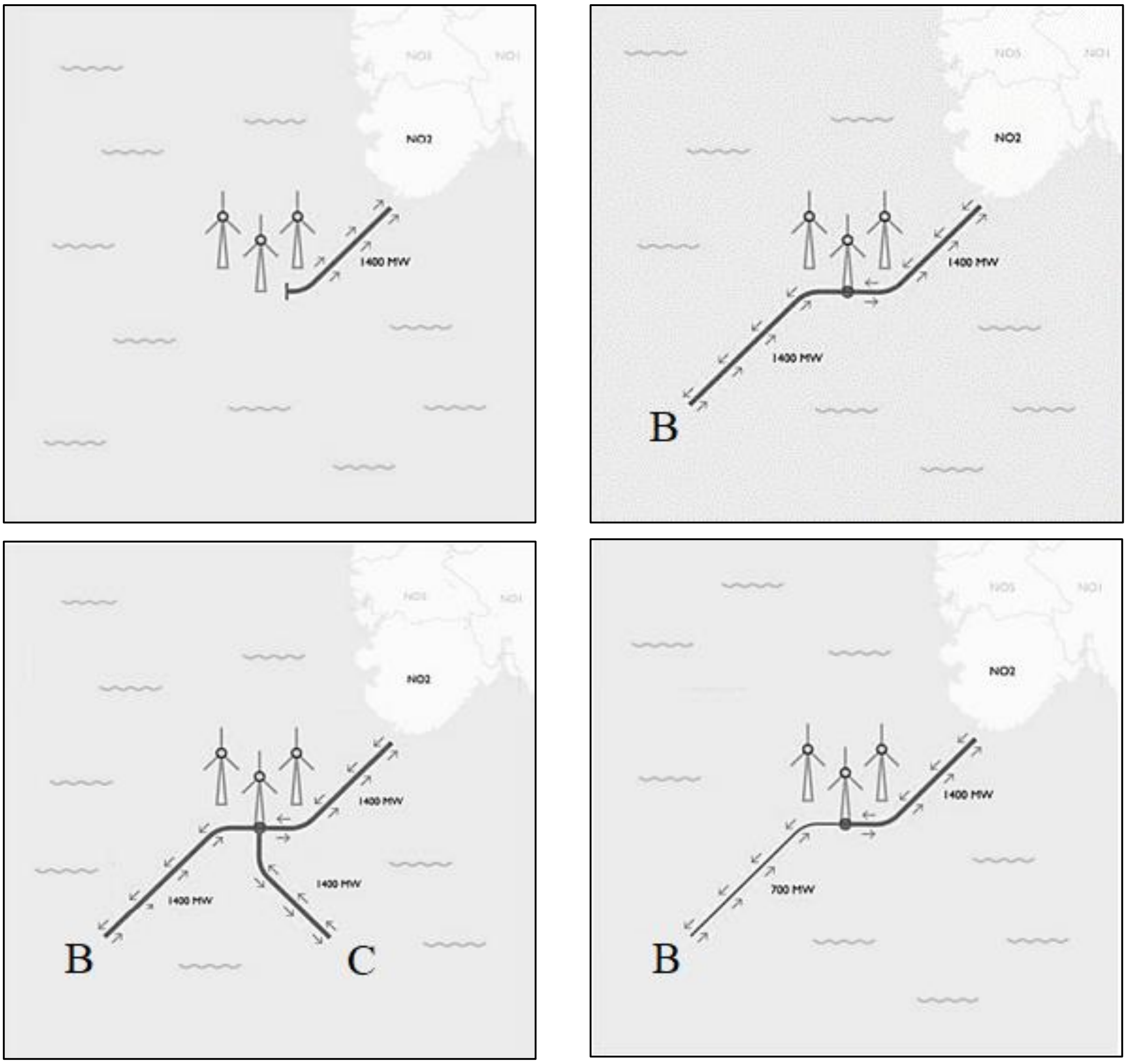

Figure 1: Illustration of a radial (top left), a two-market hybrid (top right), a three-market hybrid (bottom left) and an asymmetric two-market hybrid (bottom right) (NVE, 2023).

market will export to the highest priced market until the cable is congested, thereby filling the 400 MW available to the high-priced market. The low-priced market will export the remaining 1000 MW of transmission capacity to the median-priced market. In this case the transmission cable to the median-priced market is uncongested, which then determines the OBZ price.

The owner of the hybrid grid, typically the TSO, will receive congestion income from the trade between the two or three markets (NVE, 2023; Statnett, 2022a; THEMA, 2020). Congestion occurs when the electricity flow on the transmission cable between two bidding zones are equal to its capacity. Electricity will flow between the markets as long a there is a price difference. Unlimited transmission capacity between two bidding zones results in the bidding zones having an equal price. The congestion income equals the price differences between the markets multiplied by the amount of electricity flow between the markets. Using the same example as previously used in the OBZ price formation: a two-market hybrid with 1400 MW capacity and 1000 MW offshore generation. The cable between the low-priced market and the OBZ is uncongested and therefore equally priced, meaning no congesting income. The transmission cable between the OBZ and the high-priced market is congested, therefore the congestion income equals the price difference between the OBZ and high-priced market, multiplied with the electricity flow of 1 400 MW. For a three-market hybrid the OBZ takes the price of the uncongested connection which is the median priced market. The congestion income in this case equals the price difference between the OBZ and low-priced market times the electricity flow and the difference between the OBZ and the high-priced market times the electricity flow. In both a two-market and three-market hybrid the congestion income thereby equals the difference between the highest and lowest priced market multiplied with the electricity flow is the cable sized is symmetrical.

A analysis by NVE (2023) on grid configurations reveals that a large hybrid connection generates the highest economic surplus, while the radial connection produces the lowest. The hybrid configuration's ability to generate congestion income exceeds the additional cost of constructing a connection to a foreign country, resulting in a greater net benefit. Therefore, only a radial and the two- and three-market large symmetric hybrid configuration is analysed in this thesis. Moreover, NVE (2023) suggests that the hybrid connections could potentially extend to markets such as the Great Britain, Germany, Denmark, the Netherlands, and Belgium, which are situated in the North Sea region. However, NVE clarifies that recommending a specific connection area is outside the scope of their assignment. In this thesis a connection to four markets in different grid configurations will be examined for SNII phase 2: Norway, Denmark, Great Britain, and Germany.

4 Methodology

This chapter outlines the real option methodology applied to the offshore wind power and hybrid project. The chapter starts by outlining the real option methodology and its application to investments in offshore wind in chapter 4.1. Thereafter, chapter 4.2 contains a detailed description of the model design which is followed by chapter 4.3 which outlines the how the data is collected and a detailed description of the data.

4.1 Modelling framework

In this subchapter the theoretical framework of real options is outlined in detail, with a description of real options and uncertainty modelling.

4.1.1 Real options

The real option method first introduced by Myers (1977) builds on the theory from financial option as the right, but not the obligation to undertake an opportunity to invest. The real option method differ from the traditional decision-making methods such as the net present value (NPV) method, as these does not recognize the important implications of the relationship between irreversibility, uncertainty, and the choice of timing (Dixit & Pindyck, 1994). The net present value method assumes either that the investment is reversible, meaning the investment can be undone, or that it is irreversible, that it cannot be undone. In the case of an irreversible investment, the NPV method assumes that the investment decision is a now or never proposition, meaning that if the investment is not undertaken now, it will not be available in the future. An irreversible investment is unrecoverable and therefor sunk cost. Meaning that if the investment turns out unprofitable, the asset will be equally unprofitable for other investors and there is therefore nothing to gain by selling the asset. This is the case for an offshore wind farm, as it is industry specific and equally valuable for all investors.

Specifically, a real option to defer can be classified as a call-option with the right, but not the obligation to delay the investment decision. The option to defer is only valuable if the investment opportunity is irreversible, the firm has the ability to wait, and there is uncertainty (Dixit & Pindyck, 1994).Therefore, of course, if all future conditions are known, there is no value in delaying the investment. Moreover, to have the option to delay, investors must of course have the ability to wait. This is not always the case where for example strategic considerations make it imperative that the investment is made quickly. However, in most cases the option of delaying is feasible. An additional consideration is that there might be a cost to delay. The cost can for example simply be forgone cash flows, risk of competitors entering and loss of reputation due to not delivering on stated company goals. The cost of delaying must be weighed up against the benefits of waiting for new information. Valuable information for offshore wind power projects can for example be new policies, price trends and technological development. There is consequently an opportunity cost of investing when the future is uncertain. If the value of the asset rises in the future, the payoff from investing rises, but if the asset value falls, the firm does not need to invest and can avoid making a bad investment. The real option framework provides decision makers with the tools to put a value on options and to help make better decisions (Dixit & Pindyck, 1994).

4.1.2 Uncertainty modelling

Offshore wind is exposed to numerous uncertain factors as noted by several studies (Gazheli & van den Bergh, 2018; Iniesta & Barroso, 2015; Kitzing et al., 2017; Schwanitz & Wierling, 2016) In this thesis the electricity price and initial investment cost are modelled as uncertain factors and outlined in the next subchapters.

4.1.2.1 Electricity price modelling

Fluctuations in the electricity price are a source of uncertainty when decision-makers are assessing the profitability of offshore wind power projects. According to Liu et al. (2021a) uncertainty from selling electricity mainly comes from the occurrence of three motions: 1) The electricity price suddenly jumps or falls caused by an announcement or implementation of new policies, 2) the electricity price has short-term price fluctuations around the mean value and 3) the price has a long-term drift. These occurring motions resemble a non-stationary stochastic process and have similar characteristics to geometric Brownian motion. Earlier studies have applied the GBM to represent the electricity market price (Kitzing & Schröder, 2012; Liu et al., 2021a).

A stochastic process is a variable that evolves in part randomly over time. One of the simplest examples of a stochastic process is the so-called random walk with discrete-time and a discrete-state. A discrete-time process is where variables only can change at discrete points in time. Similarly, a discrete-state process can only take discrete values in opposite to any logically conceivable value. The discrete-time discrete-state random walk can be expressed as:

$$P_t = P_{t-1} + \varepsilon_t \quad (1)$$

Where ε_t is a random variable with zero mean and unit standard deviation. The value of P today is equal to the value of P in the last period plus a random variable. An important characteristic of the random walk is that the range of possible values that P can take increases with the number of periods denoted by t. The variance of P is therefore non-constant over time. Hence, the random walk is a non-stationary process with a non-constant variance. Furthermore, the random walk satisfies the Markov property, as P_t is only dependent of P_{t-1} and therefore called a Markov process. The Markov property is important as this simplifies the analysis of a stochastic process (Dixit & Pindyck, 1994). A random walk can also have a drift denoted by δ determining the drift rate. The random walk with a drift can be expressed as:

$$P_t = \delta + P_{t-1} + \varepsilon_t \quad (2)$$

Most economic variables change continuously in contrast to the discrete-time and state random walk process. The Geometric Brown Motion (GBM) is a continuous-time and continuous-state process, meaning the variables change continuously with time in opposite to discrete, and that the jumps can take any value within a normally distributed interval with a zero mean. The GBM captures the motions of the electricity price and the desirable property of increasing uncertainty with time. The GBM can be express as:

$$dP_t = \alpha P_t dt + \sigma P_t dz_t \quad (3)$$

Where d denotes a change, P_t is the price at time t, α denotes the drift rate. σ denotes the volatility rate defined as the standard deviation of the underlying price. Both α and σ are constant. dz_t is the independent increment of a Weiner process equal to $\varepsilon_t\sqrt{dt}$, where ε_t is normally distributed with a zero mean and a standard deviation of one. The Wiener process has three important properties. Firstly, it is a Markov process, meaning the probability distribution for all future values only depends on its current value. Secondly, the process has independent increments, which means that the probability distribution for changes in the process is independent of any other time interval. Lastly, changes in the process over time are normally distributed with a variance that increases linearly with time (Dixit & Pindyck, 1994). In short, the first term is modelling a deterministic trend in the price movements, and the second term is a stochastic process modelling unpredictable price movements increasing in size by the square root of time.

Strategic managerial decisions are made at discrete moments, rather than in continuous time. The GBM is the continuous limit form of a discrete-time random walk when the time interval and step length go to zero and can be approximately represented by a multi-period binomial lattice stochastic process. To derive this, time can be divided into discrete periods of length denoted *t*, and it can be assumed that the price of electricity either moves up or down by an amount u and d. The probability for an upward movement is q and the probability of a downward movement is $1\text{-}q$. The process can be expressed as done by Liu et al. (2021a) shown in formula (4).

$$\begin{cases} \mathrm{P}_{t+1,i} = u * \mathrm{P}_{t,i}, 0 \leq t \leq t_{end}, 0 \leq i \ \leq t, with\ probability\ of\ \mathrm{q} \\ \mathrm{P}_{t+1,i+1} = d * \mathrm{P}_{t,i}, 0 \leq t \leq t_{end}, 0 \leq i \ \leq t, with\ probability\ of\ 1 - \mathrm{q} \end{cases} \tag{4}$$

P_{t+1} is the electricity price in the next period, *t* denoted the period, *i* denotes the number of downward movements and *T* is the total number of periods. For example, the initial electricity price $P_{0,0}$ can either raise to $P_{1,0}$ with probability q, or fall to $P_{1,1}$ with probability $1\text{-}q$. The same goes for the following nodes. u is the range of the raise in the electricity price, where $u = e^{\sigma\sqrt{dt}}$ and d is the corresponding downward range equal to $d = \frac{1}{u} = e^{-\sigma\sqrt{dt}}$. Furthermore, the risk-neutral probability is $q = \frac{(e^{rdt} - d)}{(u - d)}$, where *r* is the risk-free interest rate.

4.1.2.2 Investment cost modelling

Offshore wind is not yet a mature technology and the technology has high investment and operation and maintenance (OM) costs (Schwanitz & Wierling, 2016). Furthermore, the technological development is uncertain, but is it expected to reduce the initial investment and OM costs as more projects are built. There is shown by researchers to be a relationship between accumulated production and subsequent reduction in production cost. The relationship is referred to as learning-by-doing (LBD) or the experience curve and has been shown by researchers to correspond with the progress of wind power technology (Gazheli & van den Bergh, 2018; Yao et al., 2021).

The learning-by-doing (LBD) curve describes an exponential relationship between an increase in accumulated production and a reduction in costs. The relationship is captured by the experience parameter. The LBD curve model in normalized form can be express as:

$$I_t = AX_t^{-E} \tag{5}$$

Where I_t denotes the investment cost at time t, A is the normalization index, X_t represents the accumulated unit production at time t and E is the experience parameter, also referred to as the learning-by-doing coefficient. The experience parameter represents the rate at which the cost reduction is achieved and can be estimated by performing a regression on historical data. To obtain a linear function, the logarithm of both sides of the equation is taken.

Building on the LBD curve, the learning rate (LR) can be derived. The LR implies that for every doubling in accumulated unit production leads the production cost to decline by some portion. The LR can be express as:

$$LR = 1 - 2^{-E} \tag{6}$$

For simplicity, I assume the LR is constant over the period analysed (Liu et al., 2021a; Zhang et al., 2014). To use the LBD-curve for estimation of future investment cost based on a constant experience parameter, the non-normalized learning curve is used:

$$I_t = I_0 \left(\frac{X_t}{X_0}\right)^{-E} \tag{7}$$

Where I_t is the initial investment cost and X_t is the total accumulated installed capacity in year t. I_0 is the initial investment cost in year zero which corresponds to X_0 which is the total accumulated installed capacity in year zero. E is the experience parameter. By using the one-factor LBD-curve to estimate future costs, it is assumed that the only factor affecting the cost in the long run is technological learning.

4.2 Model description

In this chapter, I outline the modelling of the OWP and hybrid project value. In the analysis, the uncertainties chosen as variables affecting the offshore wind farm is the electricity price and technological learning are incorporated into the investment decision model. Using the RO method, two explicit assumptions is made (Liu et al., 2021a):

1) Risk-neutral hypothesis: In the context of a complete market and no-arbitrage condition, market price fluctuations do not affect investors' risk attitudes. The rate of return on investment is determined by the risk-free interest rate.
2) Rational-economic assumption: Assumes that an investor makes decisions based on rational analysis and should make decision that maximize the economic benefits of the project.

Furthermore, the assumption is made that the offshore wind farm is fully operational after the project is built, and any temporary suspension is not considered. In addition, the assumption of a stable macroeconomy in the period is made and there is no competition among investors of making the investment in the offshore wind power project once the license is awarded (Liu et al., 2021a; Zhang et al., 2017).

4.2.1 Project value

The value of the OWP and hybrid project is determined by the annual profit and the initial capital expenditure. The cash inflow of the OWP project are from electricity sales, and the cash outflow other than capex are the operation and maintenance expenses and taxes. The revenue of a hybrid project is revenue made by OWP project and the congestion income. The annual profit of the OWP project and the hybrid project in year *t* can therefore be expressed as:

$$\pi_t = ER_t + \delta CI_t - OM_t - FiT_t - Tax_t \tag{8}$$

Where π_t is the annual profit for the OWP or hybrid project dependent on δ which takes the value 1 for a hybrid project and 0 for the OWP project value. ER_t is the annual electricity sales revenue and CI_t is the annual congestion income. The cash outflow is denoted by OM_t, FiT_t and Tax_t which is the annual operations and maintenance cost, feed-in-tariff, and the annual tax payment in year *t*. The detailed breakdown of the calculations is as follows:

$$ER_t = P_t \cdot PGH \cdot IC \tag{9}$$

$$CI_t = P_t^{Diff} \cdot 8760 \tag{10}$$

$$OM_t = C_t \cdot IC \tag{11}$$

$$FiT_t = PGH \cdot IC \cdot r_{fit} \tag{12}$$

$$Tax_t = (ER_t - OM_t - \mathrm{D_t}) \cdot r_{cit} \tag{13}$$

Where P_t is the electricity price in year *t*, *PGH* is the annual power generating hours and *IC* is the installed capacity. P_t^{Diff} is the difference in electricity between the highest and lowest priced onshore bidding zone connected to the OBZ in year *t*. C_t is the operation and maintenance cost per unit installed capacity, r_{fit} is the feed-in-tariff rate, D_t is the annual depreciation and r_{cit} denotes the corporate income tax in year *t*.

In the traditional NPV model which does not consider the uncertainties, the project value at can be expressed as:

$$NPV = \sum_{i=t}^{t+T} \frac{\pi_t}{(1+r)^{(i-t)}} - I_t - CP_t - \delta(I_t^{Grid} - CP_t) \tag{14}$$

Where *t* denotes the time of which the decision can be made, and *T* denoted the lifetime of the project. I_t^{Grid} is the investment cost for the transmission cable and CP_t is the construction payment the OWP developer serves the TSO for providing the grid. The construction payment is served to the TSO by the OWP developer, which only amounts the full investment in a radial configuration. Therefore, for a hybrid project the whole grid investment is added. The NPV in this model does not account for the electricity price uncertainty and technological learning.

However, decision-makers can invest in the offshore wind project at any time for t ($1 \leq t \leq t_{end}$) to get the project value. Where t_{end} denotes the last period for which the DMs can invest in the project, also called the maturity date of the option. Meaning that when $t < t_{end}$ investors have an option to defer the investment decision to the next period. Rational investors will then choose to make the investment now or later, by comparing the current and future value of the project. The real option value calculation using the binomial lattice method is outlined in the next section.

4.2.2 Binomial lattice decision process

Cox et al. (1979) suggested a binary tree option pricing model that operates in discrete time to handle complex real options, because strategic managerial decisions are typically made at specific points in time, rather than being continuous. Although option-pricing methods were initially created to evaluate financial options, their potential use in appraising options on real assets was quickly recognized. The binomial lattice can be viewed as a probability tree with binary branches of outcomes depending on an upward or downward movement.

The value of an project with a single stochastic process following a GBM represented by a binomial lattice stochastic process, will take one out of two values for each node in the following period. The project value will either increase or decrease based on an upward or downward movement in the electricity price. A tree-period binomial decision process can be shown as in Figure 2.

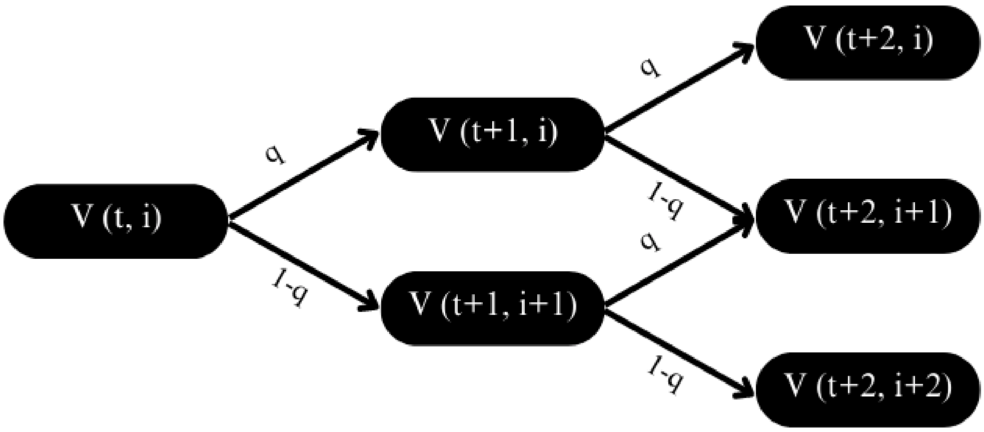

Figure 2: A binomial stochastic decision process

The net present value of the project's revenue V(t, i) is calculated for each node, and represents all possible cash flows except the initial investment cost. The value is calculated with the formulas shown in eq. *(15)*:

$$V(t,i) = \sum_{i=t}^{t+T} \frac{\pi_t}{(1+r)^{(i-t)}} \tag{15}$$

Where t is the period at which the decision is made, and T denotes the project's lifetime. By extending the formula to include the initial investment cost $I_t - CP_t - \delta(I_t^{Grid} - CP_t)$ the NPV can be derived of an immediate investment in the project*:*

$$V^P(t,i) = V(t,i) - I_t - CP_t - \delta(I_t^{Grid} - CP_t) \quad (0 \leq i,t \leq t_{end}) \tag{16}$$

In relation to financial options, the net present value, $V^P(t, i)$ of a project can be seen as the underlying value of the asset at each node. The deferral options can be seen as an American call option, meaning investors can invest in any period before expiration at time t_{end}. Investors should evaluate the project at each node in the binomial lattice and face two options; invest now or to wait. Investors should choose the strategy that maximizes the expected value, which can be calculated using the method of backward induction. Starting at the last period, when $t = t_{end}$, investors face the decision whether to invest now, or to give up their option to invest. If the project value is less than zero, the strategy yielding the highest return is to give up the option to invest, which results in a project value of zero. The investment decision at time t_{end} can be expressed as:

$$W(t_{end},i) = max[V(t_{end},i),0] \tag{17}$$

For periods where $t < t_{end}$, the backward induction is calculated as follows:

$$W(t,i) = max\{e^{-rdt}[qW_{t+1,i} + (1 - q)W_{t+1,i+1}], V\} \quad (0 \leq i) \qquad (18)$$

Furthermore, the NPV of the investment with the delayed option integrated can then be expressed as:

$$V^D(t,i) = max[W(t,i) - I_t - CP_t - \delta(I_t^{Grid} - CP_t), 0] \quad (0 \leq i) \qquad (19)$$

At all nodes investors need to compare the value of immediate investment and the expected value of delaying the investment. Then, finally the investment value at each node in the real option method is:

$$V = max[V^D, V^P] \qquad (20)$$

The real option value (ROV) of the project can be expressed as equal to the value of the immediate investment denoted NPV, and the deferred option value denoted C, which can be expressed as: $V = NPV + C$. If the value of delaying the investment is less than the value of immediate investment, the immediate investment should be made. Otherwise, the deferral option should be exercised until the deferral option equals zero at time t_{end}.

To determine the optimal investment timing, this thesis uses a altered notion of Appropriate Development Timing (APT), which was introduced by Tian et al. (2013). Specifically, APT denotes the year in which the save-path rate surpasses 50% for the first time, which indicates that the likelihood of gain outweighs the likelihood of loss. Instead of counting the number of nodes which has a positive project value, I find the save-path probability of the project value being positive through interpolation of the accumulated probability curve.

4.3 Data collection and data description

The present subchapter describes the data collection and the calculations of input parameters in the model, using the formulas previously presented.

4.3.1 Project case description

Sørlige Nordsjø II is approximately 200-250 km off the Norwegian coast close to the economic zone of Denmark. The area benefits from strong wind conditions and an offshore wind farm can reach a capacity factor of 55% which corresponds to 4 900 full load hours found in NVE (2023) simulations. Phase 2 of SNII is planned to constitute of 1 500 MW installed capacity and the transmission capacity from the OBZ to any market is set to 1 400 MW, which is the dimension for error the Nordic power network can handle (Statnett, 2022a). The economic lifetime of the offshore wind farm is set to 25 years (NVE, 2021). The project can be postponed 8 years, with 2031 as the final year, at which the investment has to be executed or abandoned. 2031 is modelled as the final year because phase 1 is set to be built in the latter half of the 2020 decade, and although there is not a set date for phase 2, I therefore assumed that a buildout of phase 2 will commence in the beginning of the 2030 decade. The risk-free rate is set equal to a 10-year Norwegian governmental bond which in 2023 is in the area of 3%.

4.3.2 Electricity price

The hourly historic electricity prices from 2015-2019 is gathered from ENTSO-Es transparency platform for each of the onshore bidding zones analysed in this thesis. The years after 2019 is omitted from the analysis due to the extraordinary situation in the European power market caused by the corona pandemic and the invasion of Ukraine. NO2 is the electricity price in the southern part of Norway, DK1 consists of the regions Jylland and Syddanmark, GB is the bidding zone in Great Britain consisting of England, Scotland, and Wales. Lastly, DE is the bidding zone in Germany, Austria, and Luxembourg until 2018 when Austria became a separate bidding zone. There is constructed six electricity prices for a OBZ under two- and three-market hybrid configurations with a combination of the onshore markets used in this thesis. The price formation is based on hourly historical prices and represent a hypothetical offshore bidding zone. The potential price effect from OWP generation and trade is not accounted for in the analysis. Based on the OBZ market design the constructed OBZ electricity prices between two markets are the minimum of the two markets, meanwhile in a three-market hybrid configuration the OBZ takes the median price as described in chapter 3.2.

In Figure 3 the annual average price for the onshore bidding zones is shown. During the period the yearly power price in NO2 and DK1 is similar in terms of price level and annual variation. On an hourly basis NO2 and DK1 are equal 43,6 % of the time, and in 39,6 % of the hours DK1 is greater than NO2. In this period, the Norwegian power price have on an annual basis been the lowest, except for in 2019 being slightly higher than both DK1 and DE. Furthermore, it can be seen that the annual average in all markets have a positive correlation. This can be due to the markets being interconnected through transmission cables and thus are affected by the same drivers. Notably, the average annual electricity price is significantly higher in GB

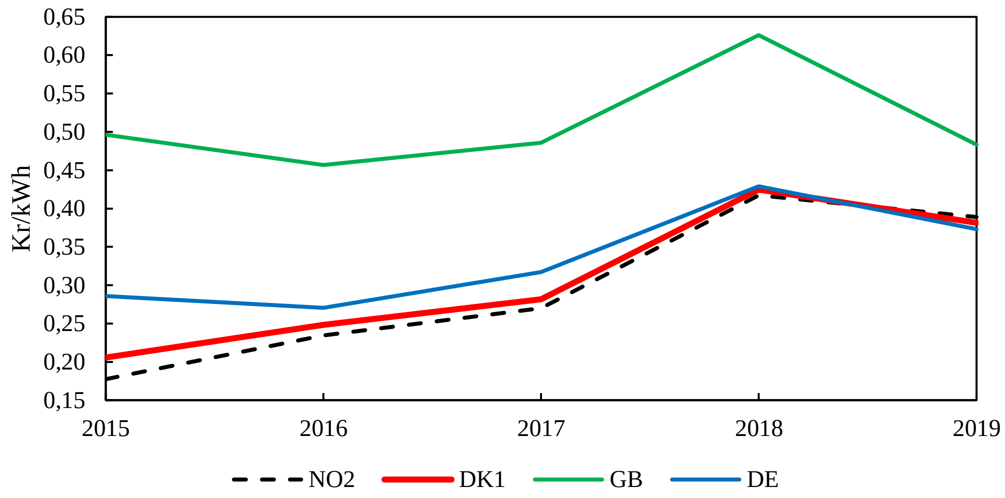

Figure 3: Historical average prices in the bidding zones NO2, DK1, GB and DE

than in the other markets and compared to NO2 the price in GB is higher in 96,8 % of the hours in this period. Moreover, the DE price is higher than NO2 in 70,1 % of the hours.

The electricity prices in the OBZ are presented in Figure 4 for the two-market hybrid configurations. These OBZ prices are compared to the price in NO2, which represents the price that an OWP developer would receive under a radial grid to Norway. Notably, the OBZ prices in all hybrid configurations are lower than the NO2 price. This is due to the OBZ taking the lowest hourly price. Among the hybrid configurations, the NO-GB configuration exhibits a price that is the most similar to NO2, while the NO-DE configuration yields a significantly lower price. There are two primary factors contributing to this phenomenon. Firstly, GB typically represents the higher-priced market in comparison to NO2, resulting in NO2 prices mostly being the minimum of the two markets. In the NO-DE hybrid, DE prices are more frequently lower than those in NO2, compared to NO-GB hybrid, leading to a lower average price. Secondly, DK1 represents the lower-priced market in a hybrid with NO2 more often than GB and DE. However, the NO-DK configuration has a higher average price than NO-DE, suggesting that the low-priced hours in DE are lower than those in DK1.

Notably, the difference between NO2 and OBZ prices has been increasing over the period under review. In 2015, NO2 represented the low-priced market in a larger proportion of hours than in 2019 in all hybrid configurations. This may be attributed to various factors, including but not limited to, the prevailing trends in the electricity markets, such as the increasing interconnection of power grids and the greater deployment of renewable energy sources. However, the precise cause of this falls beyond the scope of this thesis.

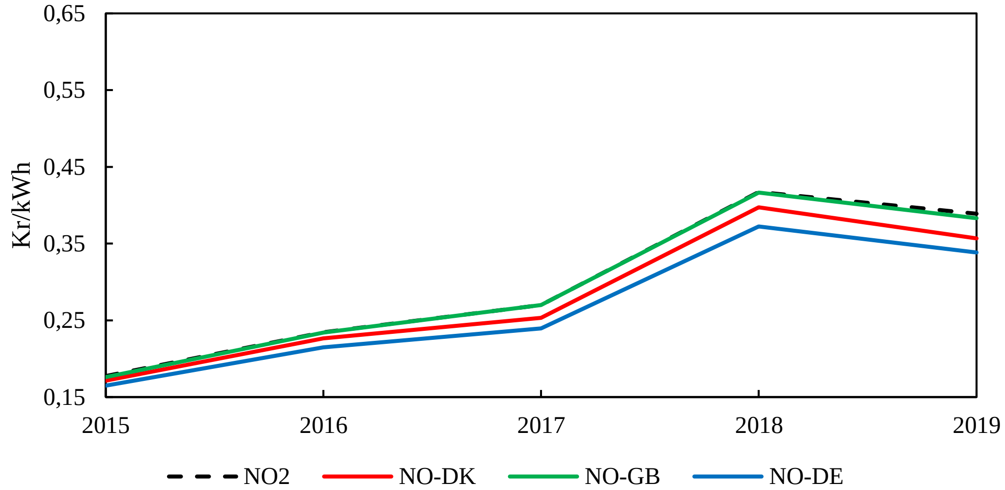

Figure 4: Historical annual power price in the bidding zones NO2, NO-DK, NO-GB, and NO-DE

The OBZ prices under a three-market hybrid grid configuration is shown in Figure 5. Not surprisingly, the OBZ price in a three-market hybrid grid is higher than for the two-market hybrid grids as the three-market hybrid grid equals the median priced market. In the NO-DK-GB and NO-DK-DE configuration, the price is equal to the DK1 price most often being equal 79,6 and 78,5 % of the hours respectively. The highest priced OBZ is in the configuration with NO-GB-DE which is equal to DE 62,7 % and NO2 28,3 % of hours.

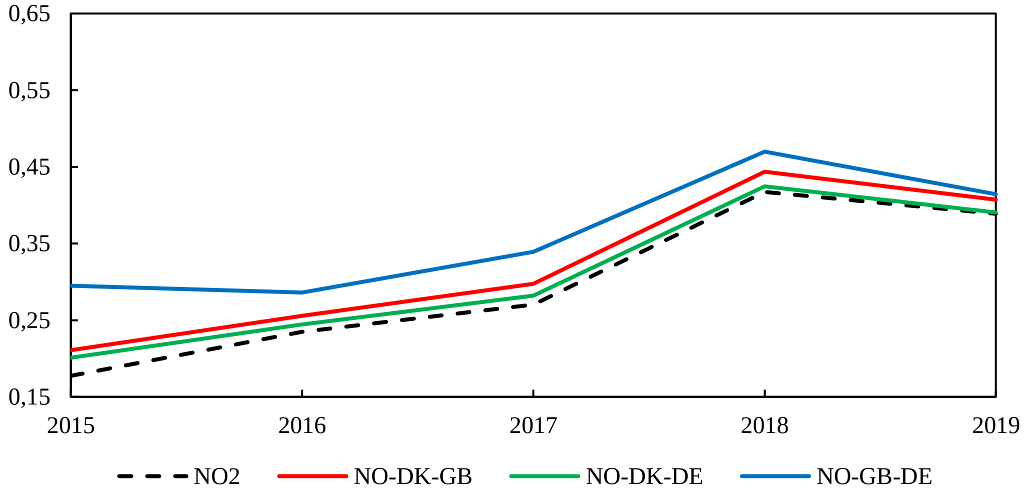

Figure 5: Historical annual power price in the bidding zones NO2, NO-DK-GB, NO-DK-DE, and NO-GB-DE

Based on the yearly average power price the volatility rate, denoted σ for each electricity price can be calculated as follows. First the logarithmic difference is taken: $u_t = ln(x_t/x_{t-1}), (t = 1, 2, 3 \cdots n)$. Then the standard deviation: $S = \sqrt{(1/(n-1)) \sum_{t=1}^{n} (x - \overline{x})^2}$ can be estimated. Finally, the annualized standard deviation also called volatility rate can be obtained: $\sigma = S\sqrt{\Delta t}$. Where x_t is the annual electricity price, n is the number of observations and Δt is the number of observations in a year. Based on the volatility rate, u, d, and q are calculated according to the formulas in 4.1.2.1 and shown in Table 1.

Table 1: Parameters used to model the power prices as a discrete GBM.

	NO2	DK1	GB	DE	NO-DK	NO-GB	NO-DE	NO-DK-GB	NO-DK-DE	NO-GB-DE
Mean	0,30	0,31	0,51	0,34	0,28	0,30	0,27	0,32	0,31	0,36
σ	21,4 %	21,3 %	21,8 %	20,1 %	23,8 %	22,1 %	22,9 %	19,9 %	20,2 %	20,3 %
u	1,24	1,24	1,24	1,22	1,27	1,25	1,26	1,22	1,22	1,22
d	0,81	0,81	0,80	0,82	0,79	0,80	0,80	0,82	0,82	0,82
q	0,52	0,52	0,52	0,53	0,50	0,51	0,51	0,53	0,52	0,52

The annual volatility over the period has been near-equal on an annual basis in NO2 compared to DK1 and GB. It is worth noting that the volatility rate is calculated on the yearly average electricity price, and therefore the short-term variation is not captured. The reason for this, is that the investor's perspective is long term. Although, the daily, weekly, and annual seasonality is of interest for the investor, as it can affect what price the offshore wind farm receives. An analysis on the achieved price received by the offshore wind farm is not included in this analysis. Furthermore, the price volatility is slightly higher in the two-market hybrid configuration and lower in the three-market hybrid configuration compared to NO2. Indicating that a hybrid configuration does not lower price risk, but whereas the three-market hybrid grid lowers the risk slightly.

Furthermore, the electricity markets is undergoing a change towards renewable energy sources and the future price and volatility may not be the same in the future. Statnett (2023a) presents a forward-looking model that simulate the electricity markets in the Nordics and Europe up to 2050, considering their expectations of market developments. The simulations indicate that Germany and GB are expected to experience an average electricity price of 48 EUR/MWh and 47 EUR/MWh, respectively, from 2030 to 2050. The future price is higher than the historical prices in Germany and lower than the historical prices in GB. This is due to the expectation of higher gas and CO2 prices, an unprecedented increase in wind and solar power generation in the latter half of the decade, accompanied by a growing number of flexible technologies. Statnett notes that the increase in renewable energy generation is likely to enter the market before flexible technologies, resulting in a rise in short-term volatility and an increased number of low-priced hours. Additionally, Germany and GB will still require the use of gas-fired power and lead to occasional high-priced periods. However, Statnett expects the introduction of new technologies such as hydrogen production and expanded battery capacity from 2035 onward to improve system flexibility, reducing the occurrence of both low- and high-priced hours and mitigating price volatility. Furthermore, in southern Norway and Denmark Statnett's simulations show an average future electricity price of 44 EUR/MWh and 47 EUR/MWh from 2030 to 2050. Statnett expects that both countries will experience increased intermittent renewable energy generation and entry of flexibility in their electricity markets, following broader market trends. However, Norway is expected to have lower short-term volatility due to a significant degree of adjustable hydropower but experiencing higher annual variation due to annual precipitation variability.

This thesis will analysis the effects of future expected electricity prices and changes in volatility based on Statnett (2023a) report. The simulation on future market developments is solely performed in the offshore wind farm from the investor's perspective. First, the analysis will analyse the profitability and risk with the assumptions of future electricity prices. For the two-market and three-market hybrid grid configurations, the initial price will have the same relative relationship to what is expected to be the low-priced market. Secondly, the increased short-time volatility expected around 2030, before flexibility technologies enters the market, can cause a lower annual average electricity price for the OBZ, as more low-priced hours occur. Moreover, the introduction of flexibility enters the market and reduces volatility from the present level. Therefore, the analysis is performed on the difference in price between the low-priced market and OBZ prices. Lastly, I perform an analysis on the annual volatility to show the effects of larger and smaller annual variation than can occur do to a more weather dependent electricity system and from the introduction of flexibility, respectively.

Table 2: Annual average hourly price difference in the different grid configurations in kr/kWh

	NO-DK	**NO-GB**	**NO-DE**	**NO-DK-GB**	**NO-DK-DE**	**NO-GB-DE**
2015	0,04	0,32	0,13	0,33	0,15	0,34
2016	0,03	0,22	0,08	0,23	0,09	0,25
2017	0,05	0,22	0,11	0,23	0,13	0,26
2018	0,05	0,21	0,10	0,23	0,12	0,26
2019	0,06	0,11	0,09	0,14	0,10	0,16
Average	0,04	0,22	0,10	0,23	0,12	0,25

Table 2 displays the annual average hourly price difference between the low-priced market and the high-price market for all grid configurations. From the TSO point of view, the congestion income is based on price difference between the markets. Therefore, the higher price difference, the higher the congestion income, all else equal. The NO-DK-GB, NO-GB-DE, and

NO-GB has a high average price difference and therefore economically appealing from the TSO's perspective. In general, a connection the GB, being a high-priced area is desirable for the TSO, whereas a grid to Germany is in the middle, and Denmark being the least appealing.

4.3.3 Cost description and estimation

In the present chapter the data collected and estimated for the initial offshore wind farm investment cost, operation and maintenance cost (OM) and the grid investment cost is described.

According to statistics by IRENA (2023) and IEA (2022) the installed capacity of offshore wind power have increase from 3,2 GW in 2010 to 63,2 GW in 2022 with an average annually growth rate of 29%. In Figure 6 the historical global installed capacity of offshore wind is displayed alongside two independent forecasts by 4C Offshore (2022) and BNEF (2021). The forecast shows some variability which illustrates the uncertainty in the development estimates. In 2031 the forecast by BNEF and 4C Offshore estimates an installed capacity of 261 GW and 286 GW respectively. Both forecasts predict that Europe will be the largest developer accounting for 45-50% of the total installed capacity in 2031. Furthermore, China is expected to be the second largest, with 22-30%, while the remaining Asian countries account for 15% and the US portion to be about 10-11% of installed capacity. The projections indicate that the offshore installed capacity will on average grow 18-19% annually from 2022 to 2031. An average of the two forecasts are used to project the future cost of OWP technology.

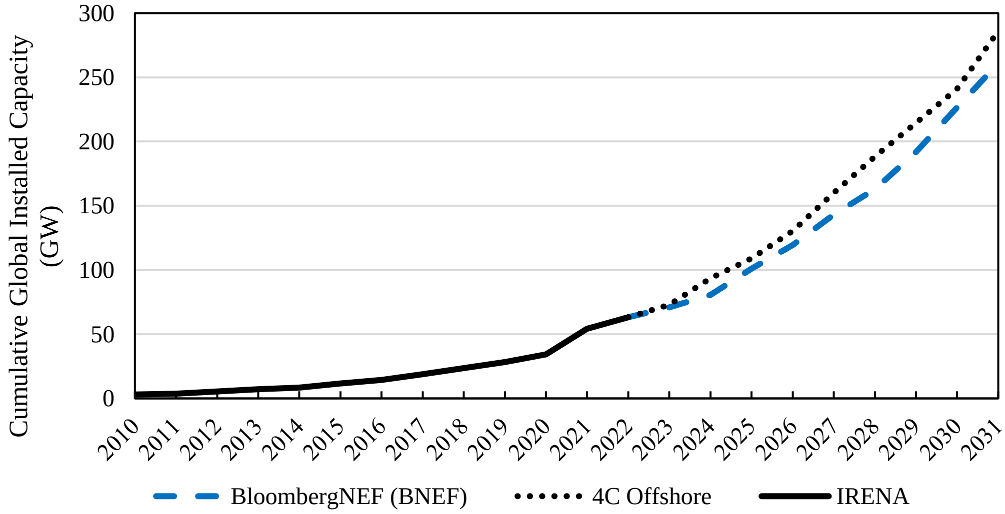

Figure 6: Historical data and forecast for global offshore wind installed capacity.

There is a great deal of uncertainty regarding the largest cost drivers such as the cost of the turbines, substructures, infrastructure and operation and maintenance. The steel price being the most important factor for the turbine cost as steel accounts for 90% of the materials used (GWEC, 2022). A report by IRENA (2022) analysed the global total average installed cost of offshore wind projects from 2000 to 2021. They find that the total installed cost increased from 2 685 USD/kW in 2000 to over 5 712 USD/kW in 2008 and did not decline noteworthy until 2015. After 2015 towards 2021 the total average cost declined rapidly to 2 858 USD/kW in 2021.

The one-factor learning rate is calculated with formula (5) and shown in Figure 7. The regression is performed with the global weighted total installed cost of offshore wind farms in 2021 USD denoted I_t and the cumulative global installed capacity denoted X_t. The resulting learning rate in the period 2010-2021 is estimated to 12,1 %.

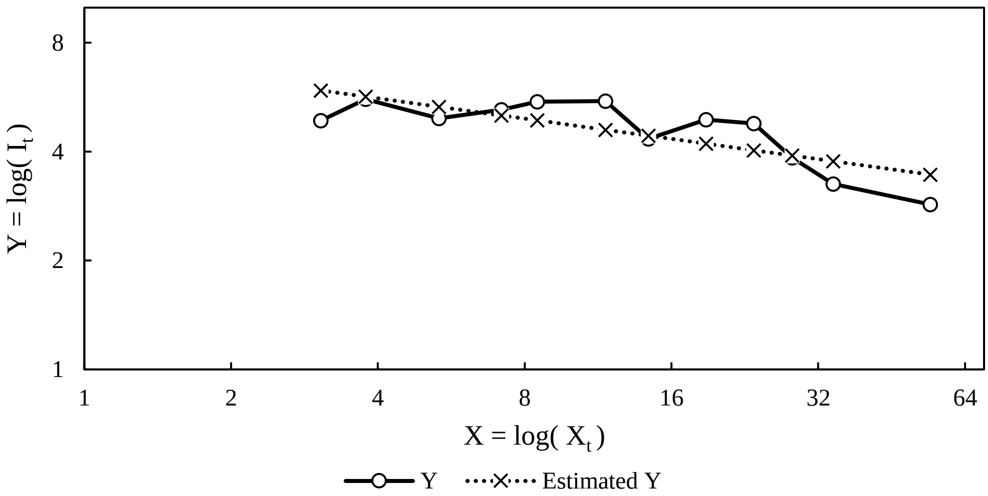

Figure 7: Linear regression analysis of global cumulative IC and total installation cost in 2021 USD/MW in 2010-2021

Yao et al. (2021) analysed the LR for offshore wind power among other renewable energy technologies in the years from 2009 to 2018. The results found offshore wind to have a one-factor learning rate of 9% and a multi-factor learning rate of 4,23 % including capacity factor and steel price in the regression. Santhakumar et al. (2022) investigated the technological progress of fixed-bottom offshore wind in the EU and UK from 1990 to 2020. The authors split the sample into two periods, before 2,5 GW cumulative installed capacity, which was reached in 2010 and after. The specific CAPEX increased in in its early development stage until 2,5 GW cumulative capacity and the period after 2,5 GW indicate a shift in technology and cost development. Santhakumar et al. (2022) results after 2,5 GW cumulative capacity show a single factor learning rate of 8 % and they performed four multi-factor models with a learning rate of 10,6 %, 10,9 % 10,4 % and 9,5 %. The four multi-factor learning curves included one additional factor for each model, starting with water depth, then adding distance to shore, farm size and turbine rated power. The two latter multifactor models with the inclusion of farm size and turbine rate power turned out insignificant and is not used in this thesis. To avoid a too small of a sample size, this thesis uses the average of the above-mentioned learning rates at 9,1% and the learning rate is constant over the period of the analysis.

Annual operational and maintenance expenditures are by multiple reports and researchers estimated to constitute 16% to 25% of the lifetime cost of offshore wind farms (DOE, 2022; Liu et al., 2021a; Ren et al., 2021; Zhao & Ren, 2015). Three of which are in the upper part of the range and therefore 25% is used in this analysis. The annual depreciation is linear and calculated based on the initial investment for the OWP project and the grid investment for the hybrid project, divided by the expected lifetime of the project of 25 years. The feed-in-tariff in 2023 for power production is set by Statnett (2023b) to 1,2 øre/kWh in 2023. Furthermore, Statnett (2022a) does a estimation based on experience and previous project on the cost of a radial connection to Norway and a hybrid connection between Norway and an average of Great Britain and Germany. The basis cost estimate for a 1 400 MW non-extendable radial cable is 1,2 billion EUR, and 2,5 billion EUR for a hybrid between Norway and GB/Germany. Furthermore, Statnett notes that a hybrid to Denmark would reduce the cost with 0,3-0,4 billion EUR compared to the cable going to GB/Germany. According to RME (2023) the regulations stipulate that the power produces should serve a construction payment to the TSO for being connected to the grid. In the regulation for onshore projects, the construction payment equals the cost of the transmission cable being built to facilitate the producer, multiplied by the reduction factor of 0,5. RME (2023) states that the current regulations are not designed for offshore hybrid projects, but infer that under a radial connection the OWP developer serves the TSO a construction payment for the whole investment. For a hybrid cable RME outlines the options that the construction payment can either be the cost of the hybrid multiplied by the reduction factor or be equal to the cost of the shortest possible connection, which is a radial connection. In this thesis the construction payment for the hybrid grid from the OWP developers' perspective is equal to the cost of a radial connection. From the regulator's perspective, the whole investment cost in grid in included in the hybrid project.

5 Results

This chapter presents the results derived from the modelling methodology outlined in chapter 4. The analysis is performed based on historical value to provide a business-as-usual type scenario and on future assumptions. The chapter starts by presenting the results from the base case scenario, first from the investor perspective, and then from regulator's perspective. Thereafter, the results from the scenario based on assumptions for the future prices is shown from the investors perspective.

5.1 Base case scenario

5.1.1 Investor's incentive to invest under different grid configurations

Taking the OWP investor's perspective, I find the profitability, the riskiness and optimal investment timing of the OWP project under different grid configurations using the real options method. For a radial connection, Table 3 and Table 4 shows the project values calculated using the model described in chapter 4 for each year, which fluctuate in accordance with the electricity price using the NPV and RO method, respectively.

Table 3: The NPV of a OWP project under a radial connection to Norway in MNOK

2023	2024	2025	2026	2027	2028	2029	2030	2031
-18 234	-10 188	-471	11 266	25 676	43 105	64 515	90 858	123 418
	-23 034	-16 389	-8 460	1 232	12 814	26 980	44 345	65 780
		-26 756	-21 306	-14 686	-6 912	2 536	14 055	28 245
			-29 671	-25 053	-19 758	-13 382	-5 671	3 801
				-31 804	-28 123	-23 749	-18 517	-12 117
					-33 571	-30 500	-26 883	-22 484
						-34 896	-32 331	-29 235
							-35 878	-33 631
								-36 494

Table 4: The RO value of a OWP project under a radial connection to Norway in MNOK

2023	2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	11 406	25 783	43 185	64 569	90 886	123 418
	0	0	0	1 339	12 894	27 034	44 373	65 780
		0	0	0	0	2 590	14 083	28 245
			0	0	0	0	0	3 801
				0	0	0	0	0
					0	0	0	0
						0	0	0
							0	0
								0

Table 3 shows that the initial year's NPV for the OWP project is -18 234 MNOK in a radial grid configuration, indicating that the profitability is inadequate to cover costs and the investment, thus resulting in a loss for the investor. Consequently, the traditional NPV method suggests abandoning the investment. Table 4 shows the value of the OWP project in each node using the RO approach which incorporates deferral options. Comparing the results in Table 3 and Table 4 reveals that the investment value computed by the RO method is equal to or greater than that obtained by the NPV method at each node. This can be seen in the analysis for all grid configurations but is only displayed for the radial connection to Norway. The RO decision-making approach accounts for the investment opportunity that is the value of waiting, while the NPV method fails to quantify the uncertainty stemming from strategic value and management flexibility, leading investors to underestimate the actual value of the project. However, the RO method's decision-making value at any node between 2023 and 2025 for the OWP project is zero, indicating that investors will suffer losses during the first three years of investment if they invest, which is consistent with the value computed by the NPV method.

In Figure 8 the save-path probability for a radial connection to Norway is shown. The save-path probability shows the likelihood of the project being on a profitable path in a given year. Meaning, what is the probability of the electricity price being at a level that render the project profitable. The optimal investment timing is the first year which the save-path probability is beyond 50%. The radial connection to Norway is below 50% the whole period in using both the NPV and RO method, and therefore the analysis shows no optimal investment timing. This implies that the possibility of profit is lower than the risk of loss from the perspective of an OWP investor, which means that the investment is likely to be unprofitable. Furthermore, it shows that the RO save-path probability is near equal to that of the NPV, which is attributed to the relatively low variation in the annual electricity price, resulting in a lower value of waiting. It can also be observed that the save-path probability is increasing over the period, primarily due to technological development that result in a reduction in the initial investment and OM costs, and the anticipation of a higher expected electricity price. However, both the NPV and RO methods indicate that the development of OWP will result in investor losses, suggesting that under a radial grid design, it is not expected that investment decisions will be executed in the analysed time frame.

Furthermore, the real-option value (ROV) and NPV are calculated for the project in the hybrid grid configurations the same way as for the radial grid shown in table 3 and 4. Figure 8 also

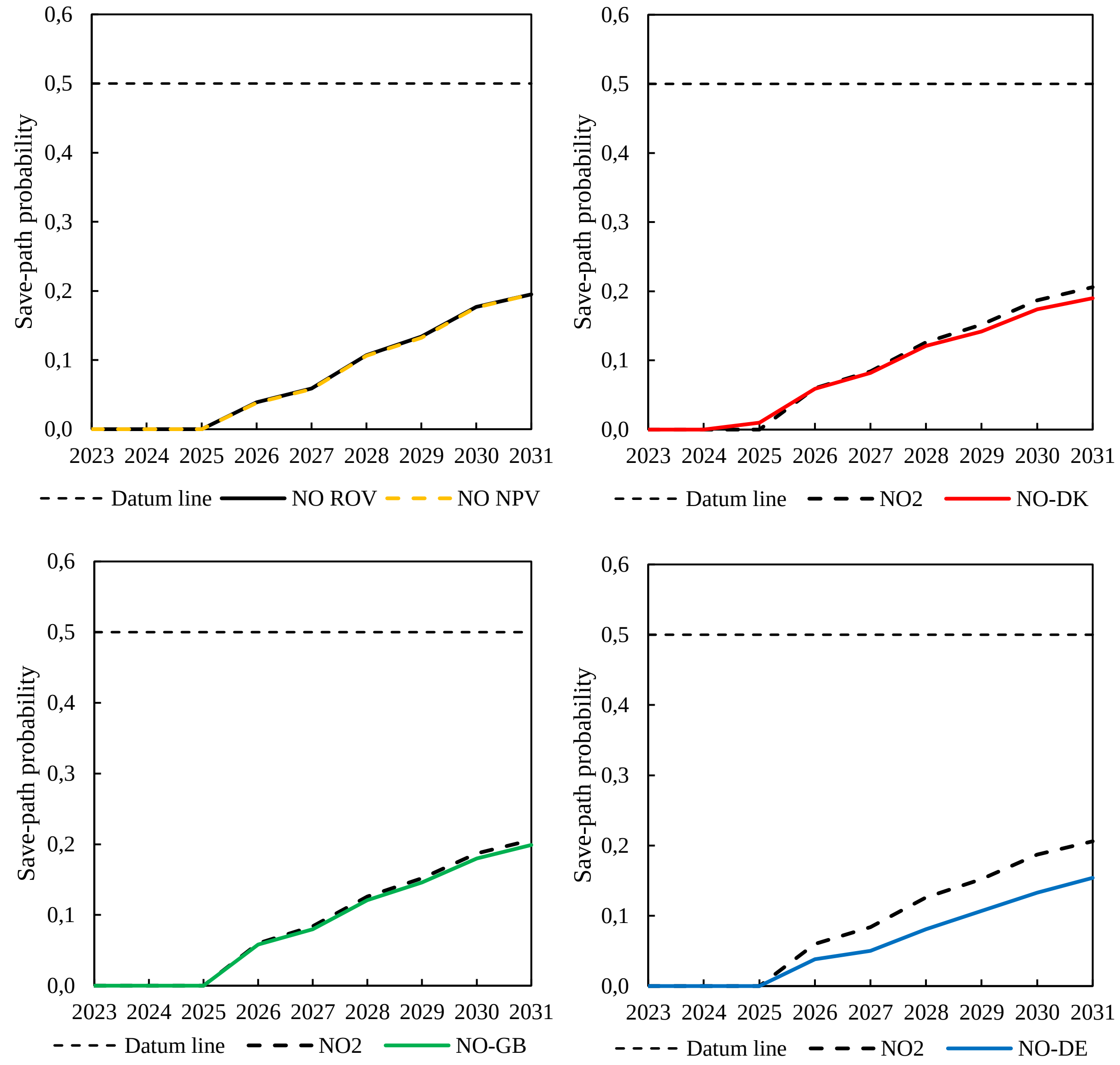

Figure 8: Save-path probability for a radial grid to Norway using the NPV and ROV method and two-market hybrid grids using the ROV method.

shows the save-path probability for the offshore wind farm connected to a hybrid grid between two markets. In the analysed time frame, the radial grid to Norway serves the OWP project an equal or higher probability of the project value being positive than the hybrid configurations, reaching its highest point of 20,6 % in 2031. The hybrid grid between Norway and Germany reaches the lowest save-path probability of these configurations, reaching 15,4 % in 2031. This can be attributed to the short-term electricity price variations in Germany, as NO2 and DE takes turns being the low-priced market. Furthermore, it is also due to Germanys low, low-priced hours as described in chapter 4.3.2, resulting in a lower average price in the OBZ. In contrast, the save-path probability for the OWP project under a hybrid grid between NO2-DK1 and NO2-GB are more similar to a radial grid connected to Norway, because NO2 and DK1 is often similar priced, and due to Norway being the low-priced market most of the time in the NO-GB configuration. Consequently, the save-path probability shows that a radial grid to Norway has a higher investment incentive for an investor, compared to a hybrid grid configuration between two markets under the OBZ design.

In Figure 9, analysis is performed on the probability distribution of the project value for the radial and hybrid configurations in 2031. The probability distribution is derived from the probability of being on each node, with the corresponding project value. In all grid designs the probability distribution is right skewed with a long right tail and a steep left side. This is due to that the electricity price cannot go below zero, which means the possible loss is limited. Moreover, the model calculates price jumps for each year as a percentage, resulting in larger upward movements than downward movements. The riskiness of the project is determined by the range of possible outcomes and their likelihood. The larger variation in project value and

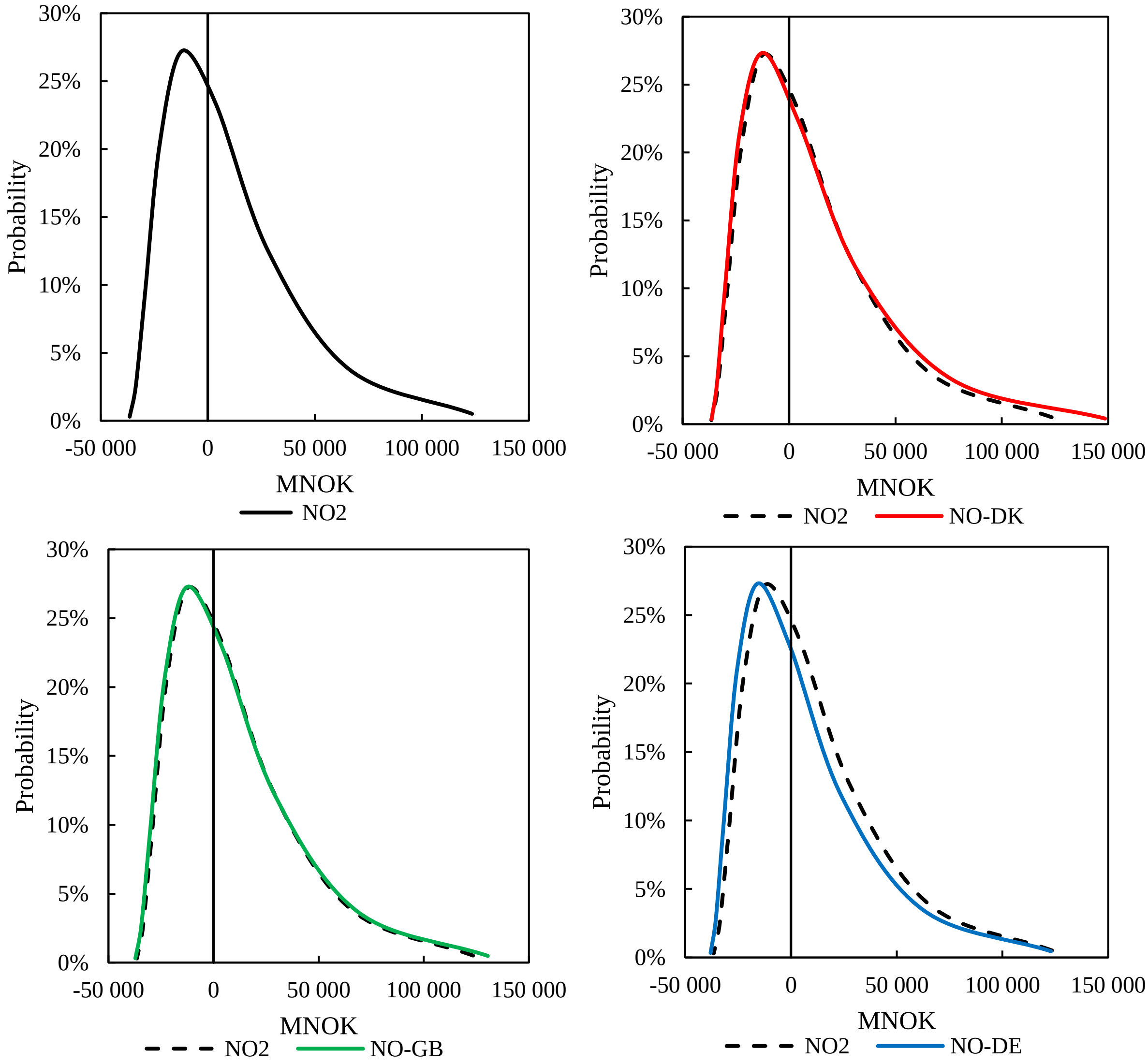

Figure 9: Probability distribution of the OWP RO project value in 2031 under a radial and two-market hybrid configuration.

therefore the wider the probability distribution, the riskier the project is. The results show that a hybrid grid between Norway and Denmark has wider probability distribution than a radial grid. This can be attributed to that the price volatility which the offshore wind farm is exposed to is higher under the NO-DK hybrid than in a radial configuration. The lower expected electricity prices in the OBZ between NO-DE shifts the probability distribution marginally to the left. Although it is shifted to the left, the right side of the distribution is similarly long, and the left side is marginally further to the left indicating a higher project risk. The small difference on the left side of the distribution can be attributed to the model design, as the downward jumps become increasingly smaller in the extreme lows. The project value in the NO-GB configuration is very similar to NO2, due to the NO-GB offshore bidding zone mostly taking the NO2 price. For a rational investor a lower volatility is desirable. Therefore, a radial connection to Norway is the preferred grid design over the two-market hybrid grid configurations in terms of risk.

In Figure 10 the save-path probability is displayed for the OWP project under a three-market hybrid grid configuration in comparison to a radial connection to Norway. The results show the project value under three-market hybrid grids has a higher save-path probability than a radial connection to Norway. The NO-GB-DE grid design reaches a save-path probability of 31,6 %, which is higher than the radial to Norway of 20,6%. This can largely be attributed to the offshore wind farm receiving a higher electricity price compared to a radial grid to Norway. The offshore wind farm receives a higher price in a three-market hybrid because the OBZ is equal to the median priced market, and the NO2 price more often lower than higher the median priced market. Furthermore, it can be seen that a connection between NO-DK-GB reaches a save-path probability of 25 % in 2031 compared to NO-DK-DE's 22,2 %, this due to NO and

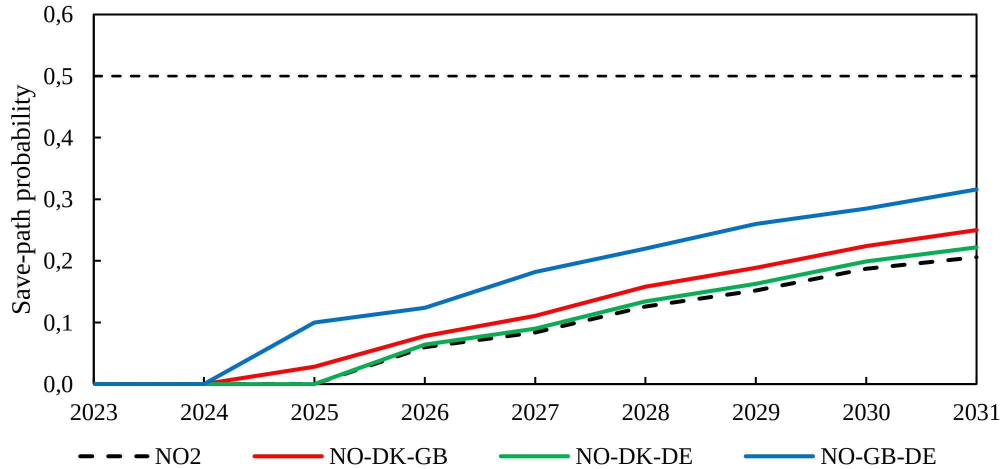

Figure 10: Save-path probability for a radial grid to Norway and for three-market hybrid grids using the ROV method.

DK mostly having a lower price than GB, but in the NO-DK-DE configuration the markets are more often taking turn being the low and median priced market, which leads to a lower OBZ price. The save-path probability is below 50%, meaning the project has a higher change of being unprofitable than being profitable in 2031, and no optimal investment timing is reached. This indicates that a rational OWP developer is not likely willing to invest in in a radial or three-market hybrid grid in the analysed timeframe given the condition used in this analysis.

The probability distribution of the OWP project value in 2031 under a three-market hybrid is shown in Figure 11. As noted previously, all distributions are rightly skewed due to a percentage change in the prices, causing upward movements to be higher than downward movements and there is limited possibility of loss which makes the left side steep. The results

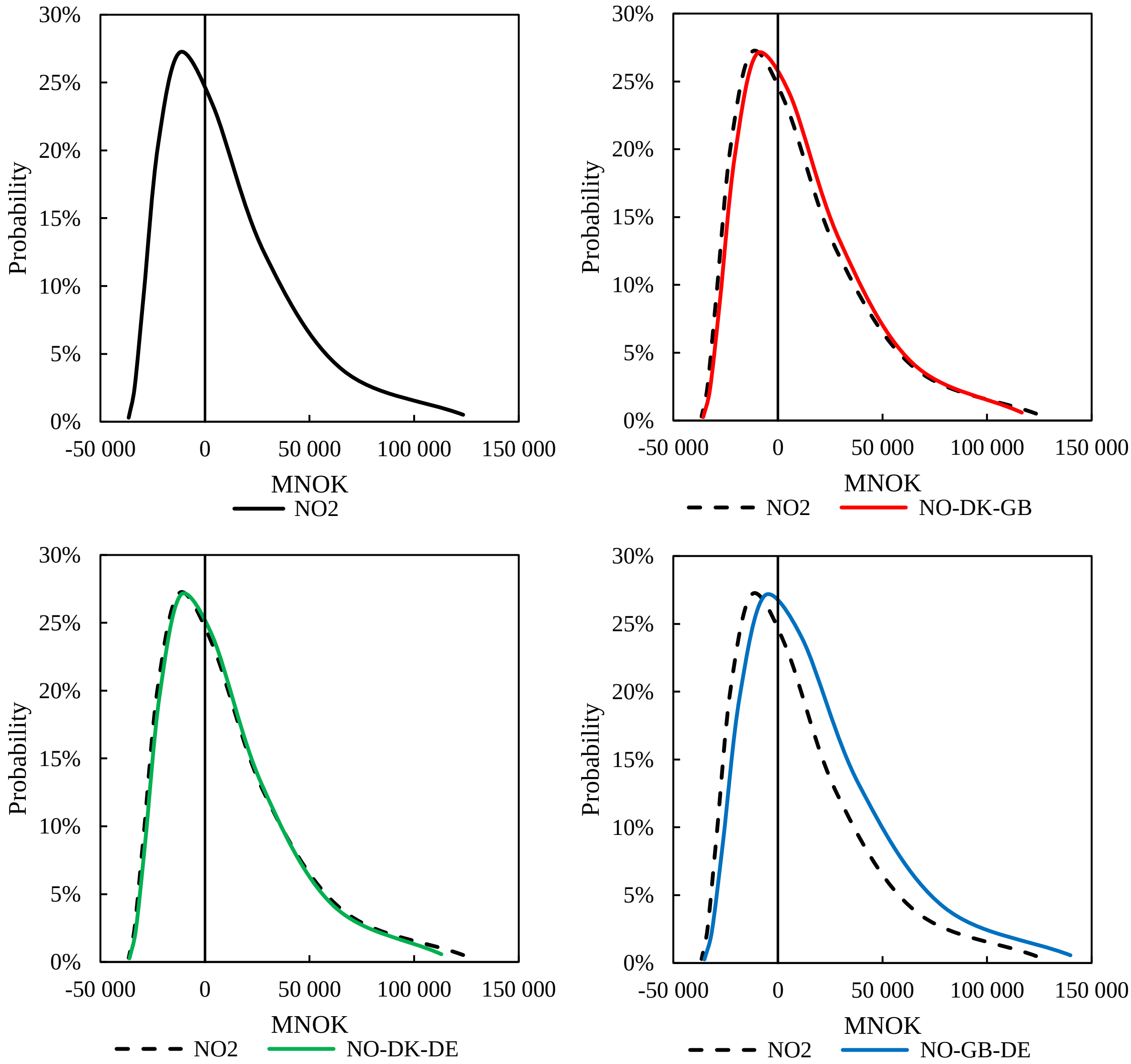

Figure 11: Probability distribution of the OWP RO project value in 2031 under a radial and three-market hybrid grid configurations.

show that the distribution of the project value under all three-market hybrid configurations is shifted to the right compared to the radial grid. This is due the initial electricity price for all three-market hybrid grids being greater than for NO2. The project value in the NO-GB-DE hybrid grid is significantly shifted to the right compared to the radial grid. The OBZ price in the NO-GB-DE configuration does also have a lower volatility, but the project value in the NO-GB-DE configuration has a wider project value distribution than the radial grid. This can be attributed to the initial price being higher in the model, which leads to larger upward jumps increasing the right tail of the distribution. Moreover, the differences become increasingly larger in the extreme high electricity price nodes and smaller in the extreme low prices nodes as the jumps become larger and smaller, respectively. Consequently, NO-GB-DE configurations show a marginal decrease in downside risk and a larger increase in the upside risk compared to the radial grid. The initial price in the NO-DK-GB and NO-DK-DE configuration is more similar to radial grid and therefore the decrease volatility results in a marginally narrower probability distribution compared to the project value under the radial grid.

From the perspective of OWP investors, the findings suggest that an offshore wind farm located in SNII is unlikely to be on a profitable path by 2031 in the absence of subsidies. Consequently, the findings do not indicate an optimal investment timing, but to defer the investment until 2031 when it is most likely abandoned. Despite the global upsurge in OWP development, the anticipated reduction in investment expenses would not suffice to render the investment profitable within the stated timeframe. Additionally, the results reveal that a three-market hybrid grid design interconnecting Norway, Great Britain, and Germany is the most appealing solution for investors, providing a higher probability of the investment being made. In terms of ranking the attractiveness of various grid designs for investors, any three-market hybrid grid configuration is preferable to a radial grid design. Moreover, a radial grid is more desirable than a two-market hybrid grid under the OBZ market design in SNII.

5.1.2 Regulator’s perspective on different grid configurations

When evaluating a project, regulators consider the socio-economic surplus and other associated consequences. While this thesis does not address the overall socio-economic appeal, it expands its scope by encompassing the TSO’s investment and thereby analyse the whole hybrid project.

Figure 12 shows the save-path probability for the two-market hybrid project between the markets analysed in this thesis. From a regulator's standpoint, the radial connection to Norway has the same project value as perceived by investors, as the OWP developer finances both the offshore wind farm and the radial grid. And without the possibility of trade, the TSO does not receive congestion income. The findings reveal that a hybrid project to any of the markets examined in this thesis has a greater save-path probability from a regulator's perspective than a radial grid. This result is attributed to the fact that the additional cost of laying a cable to another market is profitable, particularly if there is a high price differential between the two markets. A hybrid grid between Norway and Great Britain has the highest save-path probability and represents a financially viable investment at present, and therefore the optimal investment timing in the NO-GB congifuration is 2023. The save-path probability for NO-GB declines from 2025 to 2026 due to the possibility of an electricity price that renders the project unprofitable is entering the model, but the save-path probability remains above 50% the whole

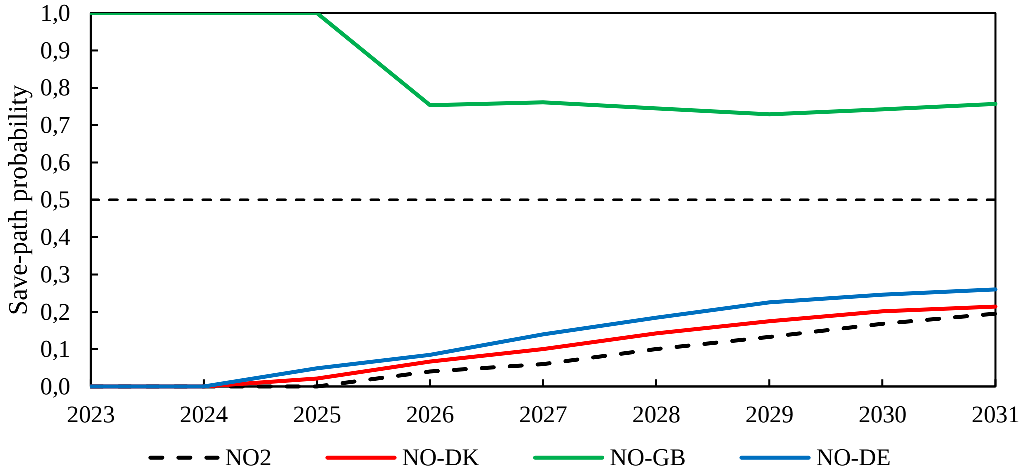

Figure 12: Save-path probability for the OWP and hybrid project value under a radial and two-market hybrid grid configurations using the ROV method.

period. In contrast, a hybrid project between Norway and Denmark has a lower save-path probability than NO-GB due to the smaller price difference between the markets, which results in an lower congestion income. Furthermore, the price difference between Norway and Germany is higher than between Norway and Denmark, and therefore has a marignally higher save-path probability. These results suggest that, over the analyzed period, a hybrid project between Norway and GB is the most desirable two-market hybrid project from a regulators perspective.

Figure 13 presents the probability distributions of project value in 2031 for a radially connected offshore wind farm and for the two-market hybrid project under a connection to the different markets. In line with the save-path probability, the hybrid project between Norway and Great Britain has a curve shifted to the right, indicating a higher probability of gain and a lower likelihood of loss. The variation in project value for NO-GB is nearly equal to the radial design, but with a lower downside risk. Comparing the NO-DK grid configuration to the radial design, the hybrid project has shifted to the left and obtained a longer right tail. This implies that the congestion income is not sufficient to fully recuperate the investment in the transmission cable, as the possible loss have increased. Although, when the investment is profitable, the project value increases due to the congestion income. Furthermore, the NO-DK hybrid grid has an increased variation in project value, which is substantially wider than the radial connection,

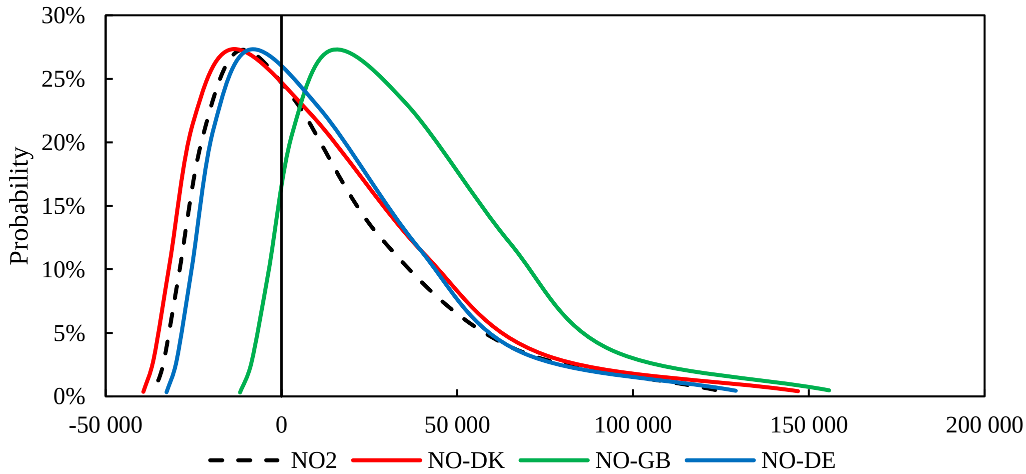

Figure 13: Probability distribution of the OWP and hybrid project value in 2031 under a radial and two-market hybrid grid configurations.

NO-GB, and NO-DE hybrid. The hybrid grid between Norway and Germany has shifted to the right, indicating an overall higher likelihood of a positive project value due to a profitable hybrid cable. Additionally, the variation in project value for the NO-DE is slightly lower than the radial connection.

The save-path probability for three-market hybrid projects is displayed in Figure 14. The results indicates that, similarly to the two-market hybrid project between Norway and Great Britain, both three-market hybrid grid configurations connected to GB has a high save-path probability and has an optimal investment timing in 2023 from the regulator's viewpoint. This can be attributed to that the congestion income acquired by the TSO, renders the project financially viable even under conditions of low electricity prices for the offshore wind farm. The save-path probability falls a few years in for both configurations as it is introduced a low electricity price into the model that would result in a negative project value for the hybrid project. Unlike the three-market hybrid grid including GB, the NO-DK-DE configuration demonstrates a peak save-path probability of 28.9% in 2031, suggesting that there is a greater likelihood of loss than profit, and that it is not beneficial from the regulator's perspective to develop the NO-DK-DE configuration.

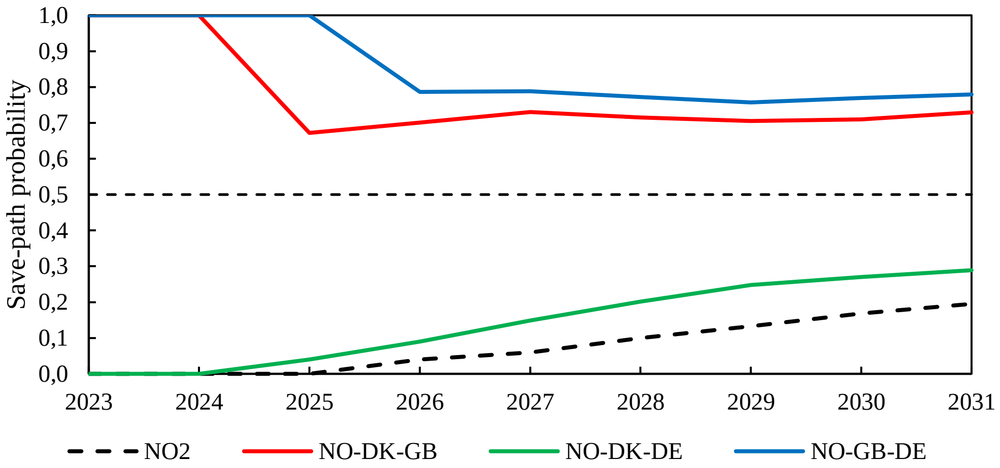

Figure 14: Save-path probability for the OWP and hybrid project value under a radial and three-market hybrid grid configurations using the ROV method.

Similar to the NO-GB hybrid project, the three-market hybrid projects connected to Great Britain demonstrate a right shift in the probability curve, as illustrated in Figure 15. Additionally, the probability curves' mid-sections for the three-market hybrid grids are wider in comparison to the radial grid. The wider mid-section can be ascribed to the increased profitability stemming from congestion income being larger part of the revenues at low electricity prices for the offshore wind farm at a lower project value. Furthermore, the right tail is less pronounced since taxes constitute a larger fraction of the income as revenue increasingly surpasses the deductible cost. Notably, the NO-DK-DE and NO-DK-GB configuration display

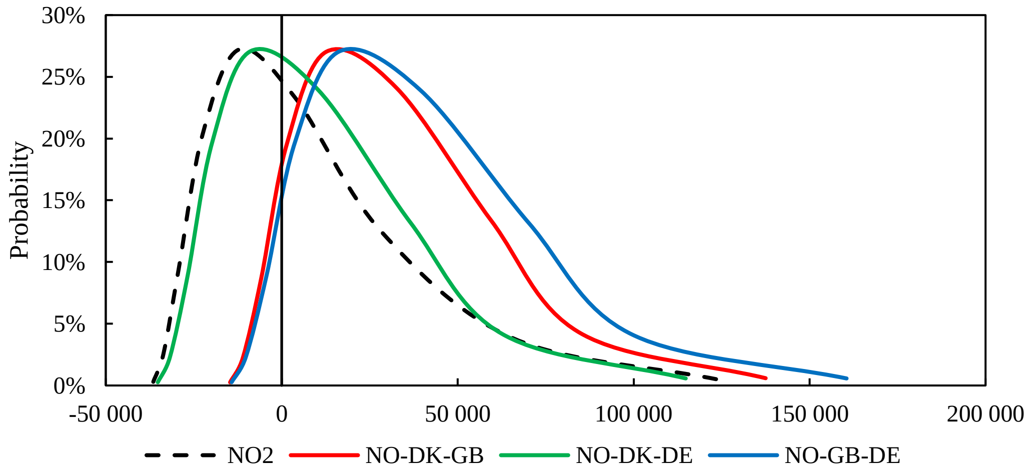

Figure 15: Probability distribution of the OWP and hybrid project value in 2031 under a radial and three-market hybrid grid configurations.

the least variation in project value, which is somewhat lower than the radial grid. Conversely, the NO-GB-DE grid exhibits a similar variation in project value compared to the radial configuration.

From the regulators perspective the results indicates that the hybrid project under a two-market and three-market hybrid configuration connected to Great Britain is profitable and has an optimal investment timing at present. Therefore, from a regulator's perspective the hybrid projects NO-GB, NO-DK-GB and NO-GB-DE is desirable. The results show that a connection to Great Britain is largely the reason why the project has a high save-path probability. This is due to the TSO receiving a high congestion income which renders the TSO's investment highly profitable, exceeding the negative project value in the low-priced nodes for the offshore wind farm. Furthermore, all hybrid grids have a higher chance of turning out profitable than a radial connection. This is also due to the revenue from electricity trade exceeds the cost of additional transmission cables in all but one instance, and thereby increasing the project value. Although the congestion income did not exceed the investment in the transmission cable in one instance, the save-path probability still increased slightly.

5.2 Future electricity market scenario

In this chapter I present the results from the analysis performed on the future expected electricity price and volatility as described in chapter 4.3. In the base case scenario electricity prices parameters are based on hourly historical power prices in Norway, Denmark, Great Britain, and Germany from 2015-2019, but the simulations on the future electricity price do not conform with the historical level. All other factors in the model are equal to the base case scenario and the initial electricity price and volatility are changed one at a time to isolate the effects.

5.2.1 Electrcity price

A report by Statnett (2023a) have estimated the future electricity prices in NO2 based on simulation towards 2050 to about 44 Euro/MWh which contributes to about 0,48 kr/kWh by today's exchange rate. The expected average future electricity price is lower than the average price in 2022, but significantly higher than the historical averages from 2015-2019 used to calculate parameters in the base case scenario. In this section, analysis on the initial power price is performed, while holding the relative price difference between the grid configurations constant.

In Figure 16 the save-path probability is shown for a radial connection to NO2 calculated by the NPV and ROV method using the simulations for the future electricity price. In 2023 the ROV indicate a high save-path probability and an optimal investment timing, meanwhile the NPV value indicate an unprofitable investment. The first period only has one simulated path, the initial price, where the NPV method indicate an unprofitable investment. In contrast, the ROV method is high enough to indicate that the investment can be profitable, when accounting for uncertainty in the future electricity price. This is surprising result as this indicate that OWP can be profitable today in a radial connection without subsidies. Further discussion on this is provided in chapter 6. After 2023 the ROV and NPV have a very similar save-path probability, with a maximum difference of 0,5% in 2024, which decreases towards 2031. The small

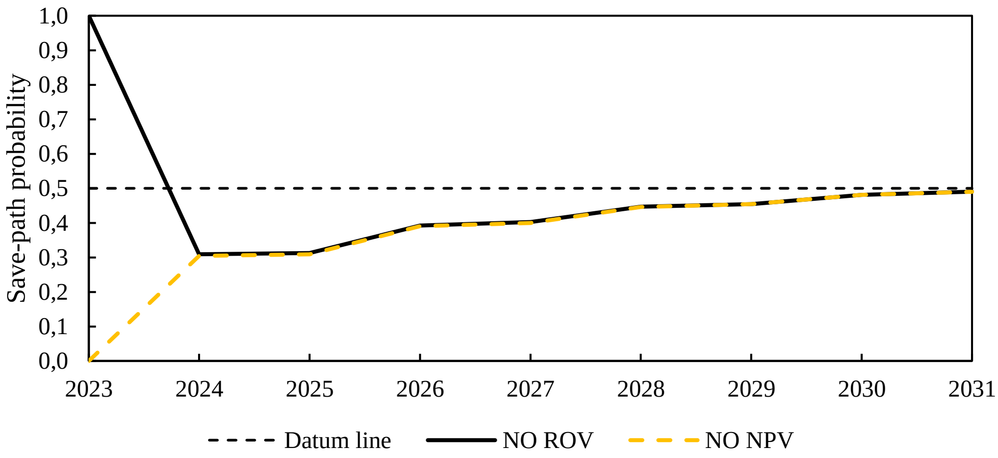

Figure 16: Save-path probability for a radial connection to NO2 under the NPV and ROV method using future simulated electricity price.

difference can be attributed to a low value of waiting, which results from an expected minor rise in the electricity price. Furthermore, save-path probability is close to 50% in 2031 indicating that an investment in OWP has a significantly higher likelihood of being realized without subsidies if the future electricity prices reach the expected level.

Figure 17 shows the save-path probability from the OWP investor's perspective for a radial, two-market hybrid and three-market hybrid configuration under the expected future power prices simulated by Statnett (2023a). All grid configurations are significantly more probable of being on a profitable path, indicating a higher likelihood of investors being willing to invest. The radial configuration reaches a save-path probability of 49 % in 2031, with NO-DK close behind at 46,5%. The two-market hybrid grid configurations do still have a lower likelihood of

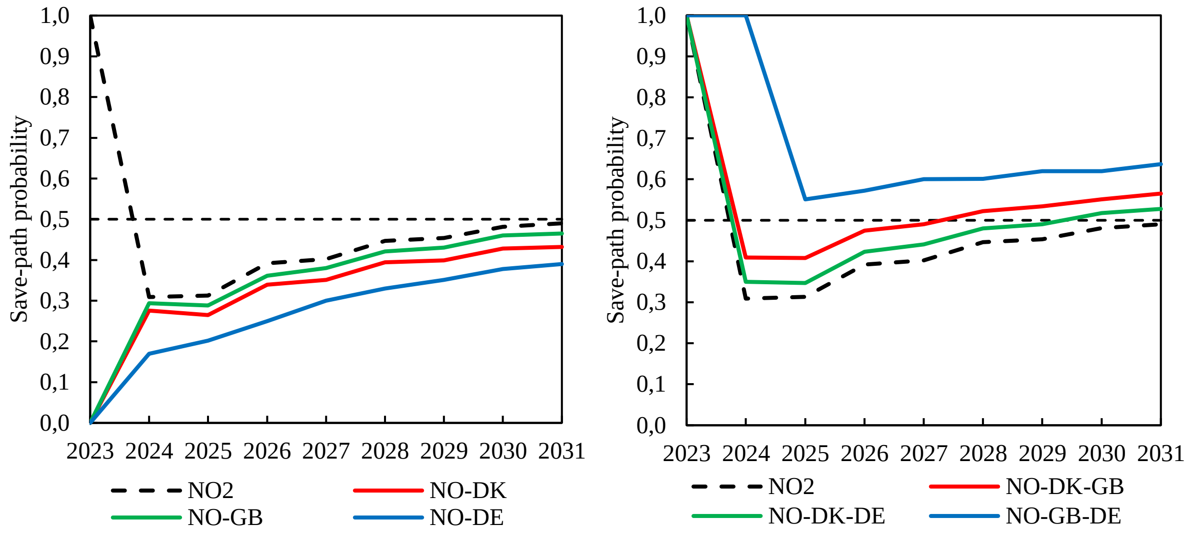

Figure 17: Save-path probability in all grid configurations from the OWP and hybrid project using the ROV method using a future simulated electricity price.

becoming profitable than a radial grid, as the percentage price difference between the OBZ and NO2 is equal to the historical relationship. However, the save-path probability is significantly higher under the expectations of future electricity prices than in the base case scenario. Moreover, the three-market hybrid grid configuration has a significantly higher save-path probability, all with a likelihood over 50% in 2023, and therefore an optimal investment timing. The NO-GB-DE grid are beyond the 50% level the whole period, reaching a save-path probability of 63,7 % in the end of the period.

Assuming a higher electricity price in Norway and Europe in the future, the likelihood of OWP project being a desirable investment is significantly enhanced. Although, the analysis is performed under the assumption that the relationship between the onshore markets is equal to the historical relationship. If the short-term volatility is elevated as simulated by Statnett (2023a) and the correlation among North Sea offshore wind farms is high, OWP developers may receive an lower average annual electricity price. Further discussion on this is provided in chapter 6. Evident by the discrepancy between the results in the base case and the simulated future prices scenario, the electricity prices secured by the offshore wind farm has a substantial impact on the feasibility of OWP projects.

5.2.2 Annual price volatility

In the report by Statnett (2023a) their simulations find that the annual electricity prices will vary enormously between different weather years in 2030. Although, towards 2040 the probable outcome in annual variations reduces significantly due to the introduction of flexibility in the system. Therefore, in this section a change in the annual volatility is analysed, while keeping all other parameters equal to the base case scenario.

In Figure 18 the save-path probability is shown for a 20% increase in volatility for the OWP project connected radially to NO2. The save-path probability is shown under the RO and NPV method. The increased volatility results in no quantifiable difference between the methods. This is due to the model design, whereas the “risk neutral probability” changes with the volatility level. The relationship between the risk neutral probability and volatility holds the value of waiting equal for differences in the level of volatility.

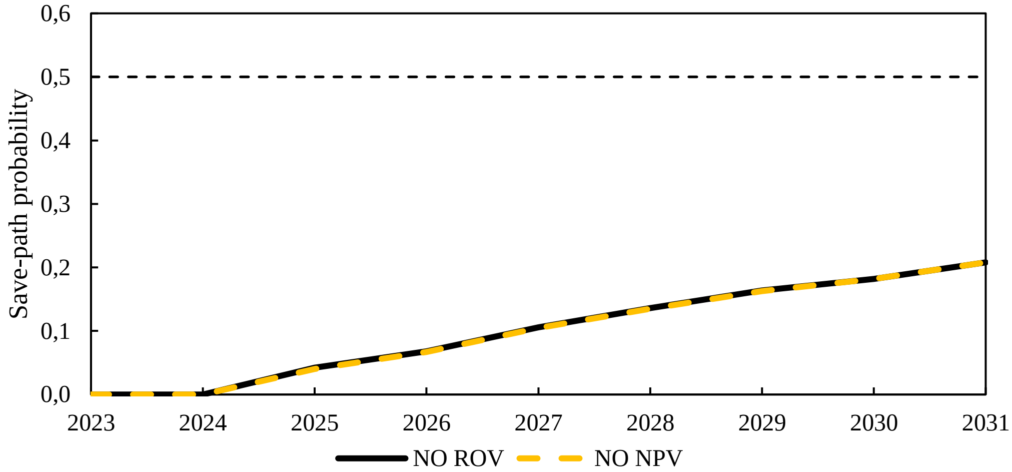

Figure 18: Save-path probability for a radial connection to NO2 with 20% increased volatility under the NPV and ROV method.

A 20% change in the annual volatility do however have implications for the save-path probability as shown in Figure 19. The increased volatility increases the save-path probability in the beginning of the period. This is due to the project having a zero, or very low probability of being profitable in the beginning of the timeframe, and the increased volatility allows for the possibility of an electricity price that will render the project profitable earlier. The opposite occurs for the save-path probability in the instance of a 20% percent lower volatility. Furthermore, in NO2, NO-DK and NO-GB the save-path probability for an increase and decrease volatility cross in the end of the timeframe analysed. In the last periods the increase in volatility marginally decreases the save-path probability, whereas the decreased volatility marginally increases the save-path probability. This can be attributed to the fact that when the project has a high probability of begin profitable, a higher volatility decreases the probability of being on profitable path and the reverse for a lower volatility. Therefore, if the project is profitable today, a low volatility is desirable, but if the project is unprofitable today, a higher volatility increases the possibility of the project being in the future. The volatility impacts the three-market hybrid grids similarly and are displayed in Figure 21 shown in the appendix.

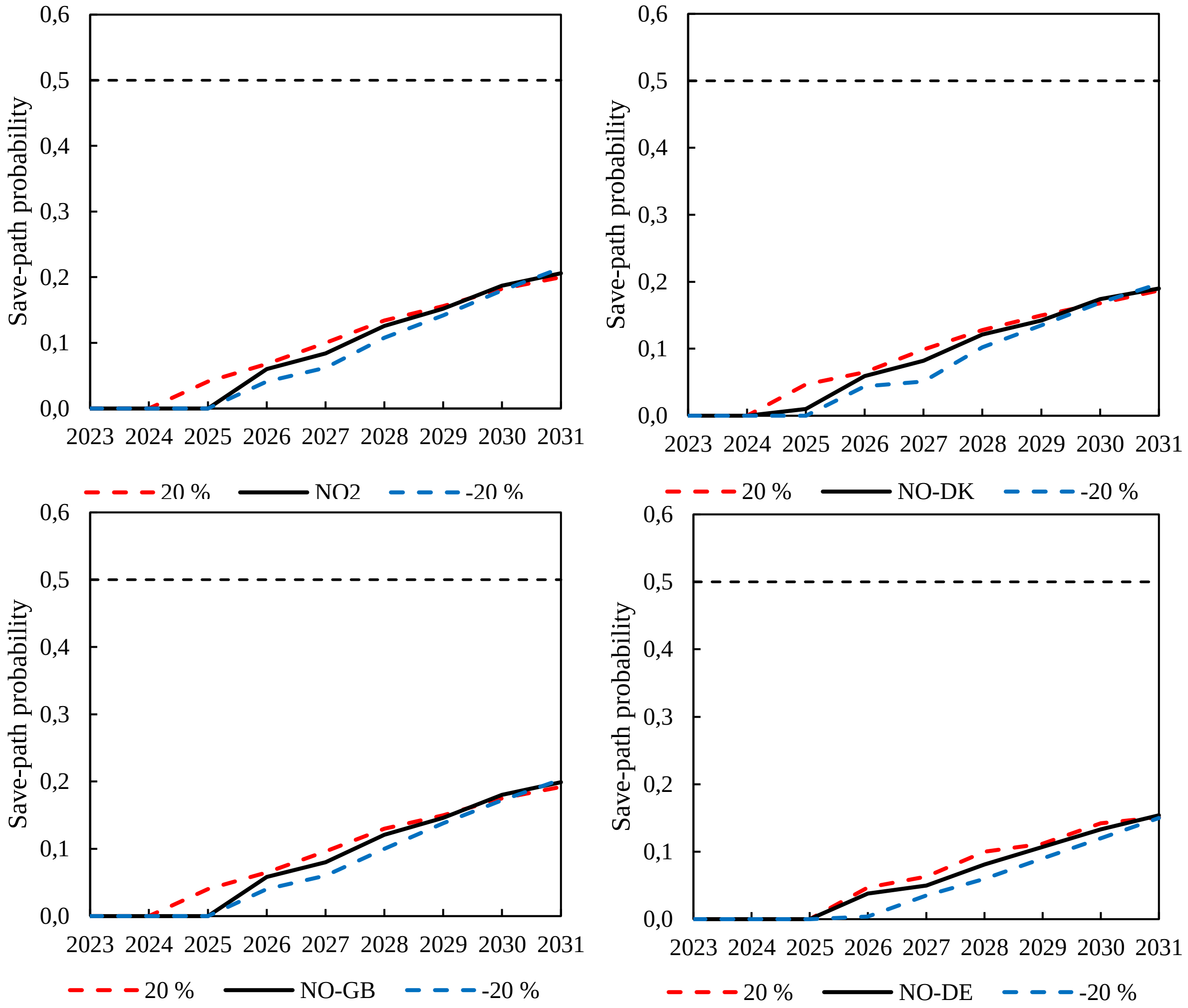

Figure 19: Save-path probability the OWP project under a radial and two-market hybrid grid configuration using the ROV method for a 20% increase and decrease in volatility.

Furthermore, a 20% increase and decrease in volatility impacts the probability distribution of project value as shown in Figure 20. Most notably, the length of the right tail is significantly smaller for a lower volatility and longer under the higher volatility, which stems from the model design. In the model design the electricity price cannot go below zero, and therefore the risk of loss is limited to the initial investment, and the present value of the costs, while the upside is unlimited. Moreover, the electricity price reaches a price near-zero in the extreme low-price node in the binomial lattice for both and increase in decrease in volatility. This results in a small difference in project value on the left side of the probability distribution. Furthermore, the annual upward and downward jumps are a set percentage based on the volatility, and thus upward jumps are larger than downward jumps, and this effect increases with a higher volatility. Therefore, the difference between the scenarios in the extreme high-priced nodes is larger.

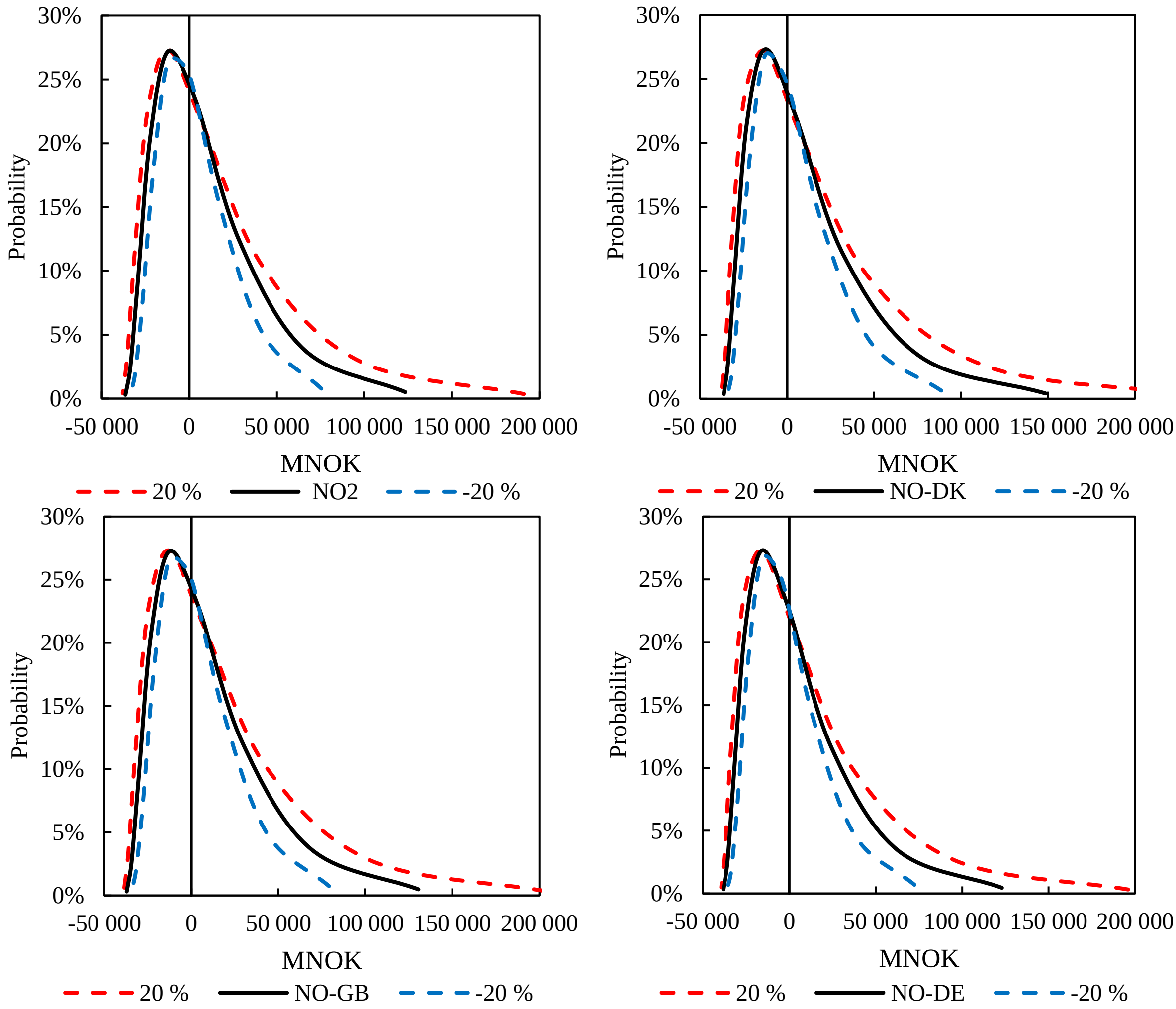

Figure 20: Probability distribution of the OWP project value in 2031 for radial and two-market hybrid configurations with an 20% increase and decrease in electricity price volatility.

Drawing from the results in the analysis conducted on anticipated future electricity prices and volatility, several observations can be inferred. Firsly, it is clear that the difference between the RO and NPV method is not affected by a change in volatility. The risk-neutral probaility vaires with volatility and therefore, the value of waiting is equal for any volatility in this RO model. The higher volatility increases the chance of the OWP project reaching an electrcity prices that will render the project profitable if the current price is unsuffiecient, whereas the reverse is true if the current electricity prices renders the project profitable. Moreover, the change in volatility significantly changes the upside in project value, but show a minor change in project value for a low electricity price.

6 Discussion

This chapter discusses the results in relation to previous research in chapter 6.1, identifies implications in 6.2 and discusses the strengths and weaknesses of the thesis in 6.3.

6.1 Research objectives

I have developed a real option decision-making model to analyse investors investments incentive in offshore wind power projects under different grid configurations in the Sørlige Nordsjø II region. With the inclusion of the investment in grid made by the TSO, thereby assessing the whole hybrid project, the regulators perspective is achieved, and I investigate whether the investors and regulators grid preferences are aligned. The analysis was first performed on parameters derived from historical data in a business-as-usual scenario, and then an analysis is performed using Statnett (2023a) simulations results for a future electricity price. To focus the analysis, four sub objectives where established which was to identify the profitability, risk, and investment timing of an offshore wind farm and hybrid project under various grid configurations. In this chapter the results are discussed in relation to the research question and compared to earlier findings. The sub objectives are presented in the same order as they were presented in chapter 1.2.

The results show that the project value calculated by the RO method is equal or greater than that obtained by the NPV method. The difference is marginal but demonstrates that the real-options approach account for the value of waiting. A higher real options value (ROV) than net present value (NPV) can be also seen in Liu et al. (2021a) and Zhang et al. (2014) who used the binomial method and compare the ROA and NPV method. Similar to this thesis, Liu et al. (2021a) also found the real options value to be marginally higher than the NPV for an investment in offshore wind power.

A two-market hybrid results in a lower profitability than a radial grid connection. The result is similar to the findings of Kitzing and Schröder (2012) who found a two-market hybrid to render the offshore wind farm the least profitable off all grid configurations they analysed. This is due to the offshore wind farm receiving the lowest prices of the two markets connected. Moreover, which market the hybrid is connected to affect the profitability. The results show that a connection to Germany is the least preferable, as the German electricity price has very low low-priced hours and is relatively often lower than the NO2 price. In contrast, a connection to

GB is the most preferable, due to the GB rarely being lower than the NO2 price. However, simulations by NVE (2023) shows that the revenue for an offshore wind farm in a hybrid connection to Germany in 2040 is near-equal to a radial connection to Norway. This indicate that a hybrid connection to Germany in the future may be more desirable than in the period this thesis is based on. Furthermore, in Statnett (2023a) outlook towards 2040, they expect a large deployment of offshore wind in GB, which may increase the number of low-priced hours. An increased number of low-priced hours will negatively affect the price which an offshore wind farm receives under a hybrid grid between Norway and GB. Therefore, there should not be drawn a conclusion on which specific is the most preferable for an OWP investor in the future, but in general, a market with higher prices than NO2, and a priced that rarely takes turns with NO2 being the lowest priced is desirable. The desirable qualities that affect how often two prices takes turn being the lowest prices in addition to an average higher price is low short-term variation and being positively correlated with NO2.

Furthermore, the profitability of the offshore wind project is the highest under a three-market hybrid configuration. This is due to the offshore wind farm receiving the electricity price equal to the median priced market. The result is somewhat contrary to Kitzing and Schröder (2012) who the finds the radial connection to be the most profitable connection. However, they find the hybrid configuration between three markets to render the offshore wind farm the second most profitable compared to a radial, two- and four-market hybrid. The difference in result can stem from that Kitzing and Schröder (2012) apply an equal initial price and stochastic parameters for the connected onshore bidding zones, whereas I use real-world parameters. Furthermore, in this analysis the market which holds a radial connection is the lowest priced market, whereas in their analysis the radial market has an equal price to the other onshore markets. The OWP project has the highest profitability under the three-market hybrid between Norway, GB, and Germany. Germany is favoured over Denmark in this configuration because the offshore bidding zone takes the median price. Therefore, the effect of Germany having lower low-priced hours than Denmark, is lower than the effect of Germany having higher high-priced hours. As noted previously, the electricity markets are changing and therefore no definitive conclusion can be made on which markets are the most desirable in the future. In general, the three-market hybrid grid it is most desirable for an OWP investor if the OBZ is connected to markets that has a higher price than NO2 with low short-term volatility and that are positively correlated with NO2.

In the evaluation of the project risk, the results show that surprisingly, a two-market hybrid results in a larger project variation than a radial connection. However, is shows unsurprisingly a lower project variation for a three-market hybrid. A higher variation in the two-market hybrids are contrary to Kitzing and Schröder (2012) results, which show a reduction in the variation of the offshore wind farm's internal rate of return for each additional market connected. However, the results from the three-market hybrid are more in line with their findings, although the variation decreases significantly more in their results. In theory, when multiple markets are connected to the OBZ, one would expect the volatility to decrease as the short-term variation is evened out. Therefore, the difference in results can be attributed to that this is not the case in reality. The Norwegian power price has lower short-term variation compared to the other markets, and when the OBZ takes the lower of the two prices, the very low prices in the foreign market increases volatility. However, with the introduction of a third market I find a reduction in volatility, which show that for three markets the short-term variations are actually being evened out.

An optimal investment timing is not reached in the base scenario. The electricity price based on the historical price level and the technological developments are likely not sufficient to render the project profitable in the future. However, when Statnett (2023a) simulations for the future electricity prices are used in the model, the optimal investment timing for the offshore wind power project under a radial and three-market hybrid grid are already in 2023. This is surprising as the IEA (2019) and DOE (2022) among others do not expect offshore wind to reach an competitive levelized cost of energy before 2030. Moreover, NVE (2023) estimates through electricity market simulations that the realized priced by a offshore wind farm in a hybrid project in SNII will be lower than the average price at about 0,45 kr/kWh in 2030 and 0,38 kr/kWh in 2040. Although the realized prices by offshore wind farm are expected to be lower than the average price, the results nevertheless show that an offshore wind farm may become viable without subsidies, if the future realized prices and cost are to become similar to the level used in this thesis.

The results show that the profitability of an investment in a hybrid project, which is the combined offshore wind farm and grid is profitable in a connection to Great Britan. Meanwhile, a radial configuration is not profitable from a regulator's perspective. The hybrid project between Norway and GB, as well as the two three-market hybrid projects to GB has an optimal investment timing in 2023. A connection between NO2 and GB provides the highest congestion income for the TSO due to the large price difference between the markets. The congestion income received by the TSO renders the hybrid project profitable although the wind farm is not profitable. Similarly, NVE (2023) and Statnett (2022a) simulation for SNII show that a hybrid grid from the TSO perspective have a higher benefit than a radial connection and that a hybrid project appears socially rational.

A two-market hybrid configuration is desirable from a regulator's perspective, but not from an offshore wind power investors perspective. A hybrid configuration reduces the price which the offshore windfarm receives, but from a regulators perspective the income from trade renders the hybrid project overall more profitable due to congestion income. Although, the investor and regulator have the same preference for what market is most desirable under a hybrid grid. Both prefer a connection to GB as the market have mostly higher prices than NO2, which have a small adverse effect on the offshore wind farm, but results in high congestion income for the TSO. However, preferences may not align perfectly in theory. As previously noted, an offshore wind investor prefers to be connected to a market which is higher priced, has low short-term volatility and positively correlated to NO2 to reduce the adverse effect of a two-market hybrid. Whereas the TSO will receive income based on the price difference, and then it is preferable to connect to a market with a high price difference, which increases when the markets are negatively correlated. Although, most markets around the North Sea are positively correlated and therefore the high prices in GB and low volatility do align the preferences in this instance.

6.2 Implications

The findings in this thesis show that should the electricity market hold the historical price level, the offshore wind farm in SNII would have to be subsidized for investors to be willing to invest. However, if the realized prices by offshore wind farms are to increase to the level simulated by Statnett (2023a) and NVE (2023) and the technological development continue to reduce costs, offshore wind farms at SNII may become profitable without subsidies. Dependent of the future development, the Norwegian Government may have to subsidies OWP investors independent of what grid configuration is chosen in order to reach its goal of 30 GW installed offshore wind capacity by 2040.

A hybrid project between Norway and high-priced markets results in the overall most profitable project. Policy makers should choose a hybrid project between two or three markets to as this configuration is the overall most profitable, whereas a radial configuration results in the overall lowest profitable project. The offshore wind farm has a higher likelihood of needing subsidizing in a two-market hybrid than a radial grid configuration, but the congestion income makes up for the loss by offshore wind power investors. In a three-market hybrid the need for subsidizing the offshore wind power investor may be lower. This implies that from a regulator's perspective a hybrid grid is beneficial economically, but it may need to subsidize the OWP investor for the project to be realized. However, all economic and non-economic considerations are not accounted for in this analysis and therefore, this thesis simply advice decision-makers on what grid configuration that would result in the most profitable hybrid project and how the investment incentive for an offshore wind power investor is affected by grid configurations.

6.3 Strengths and weaknesses

This thesis strength lies in its ability to use parameters based on historical data and its detailed modelling of the offshore wind farms cashflow. The model design is especially useful to analyse business-as-usual type cases and to identify general implication based on historical relationships. The model's weakness is to analyse how the project is affected by future changes in the electricity market, by modelling the future price formation in the offshore bidding zone. The electricity market is expected to change greatly due to more renewable energy and from the introduction of flexibility in the system. Therefore, using parameters based on historical data are not adequate to draw conclusions for decisions in the future, although it can provide some general insights. The research area could benefit from analysing the topic using electricity market simulations for the future energy system, to better replicate the market conditions that offshore wind power will operate under in the future.

7 Conclusion

Attracting offshore wind power investors is important for the Norwegian government to reach its goal of 30 GW installed capacity of offshore wind by 2040. In this thesis I propose an investment decision model to evaluate the investment incentive for offshore wind power investors under different grid configurations relevant to Sørlige Nordsjø II phase 2. The model also analyses the investment incentive in the overall hybrid project under different grid configurations taking a regulators perspective. The investment decision model is based on a real-options approach addressing uncertainty in offshore wind power projects and solves the option value by using the binomial lattice method which embeds defer options. The framework models the electricity price stochastically and the future investment cost using the learning-by-doing curve to account for technological development. I research this problem in two scenarios, one by applying parameters based on historical data and a scenario based on simulations for the future electricity market.

The analysis reveals three key insights: First, this thesis shows that from the offshore wind power investor's perspective, the grid configuration has an impact on the investment incentive. The preferred grid configuration is a three-market hybrid, whereas the least preferable grid design is a two-market hybrid with the radial connection being in between. Generally, in a hybrid configuration the offshore wind farm benefits from being connected to markets that has a higher price than NO2, with low short-term volatility and are that are positively correlated to NO2. In the base case scenario, I do not find an optimal investment timing for the offshore wind farm. This indicate that under the historical price level, offshore wind farms have to be subsidized for investors to be willing to invest. However, in the scenario based on simulated future prices the radial and three-hybrid grid reach an early optimal investment timing and shows that under higher future prices, offshore wind power may be viable without subsidies.

The second key insight is that that a hybrid configuration does not reduces the riskiness of the offshore wind power project. The results show that a two-market hybrid slightly increases the riskiness of the project compared to a radial connection, meanwhile a three-market hybrid slightly reduces the projects risk.

The third key finding is that the preference of investors and regulators in grid configuration are partially aligned. I find that a two-market hybrid is not desirable from an offshore wind farm investor perspective, but desirable from a regulator's perspective. Moreover, both investors and regulators find a three-market hybrid desirable. I find that from a regulator's perspective, two and three-market hybrid project to a high-priced market to have an optimal investment timing at present based the historic price level. This indicates that if offshore wind power investors are subsidized, the hybrid project is financially feasible from both a regulators and investors perspective.

The attractiveness of hybrid grids for different market actors depends on the configuration and what markets that are connected to the offshore hub. The results of this thesis can be used by investors and regulators when considering if a hybrid project should be established in Sørlige Nordsjø II or similar projects to make an informed decision.

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Appendix

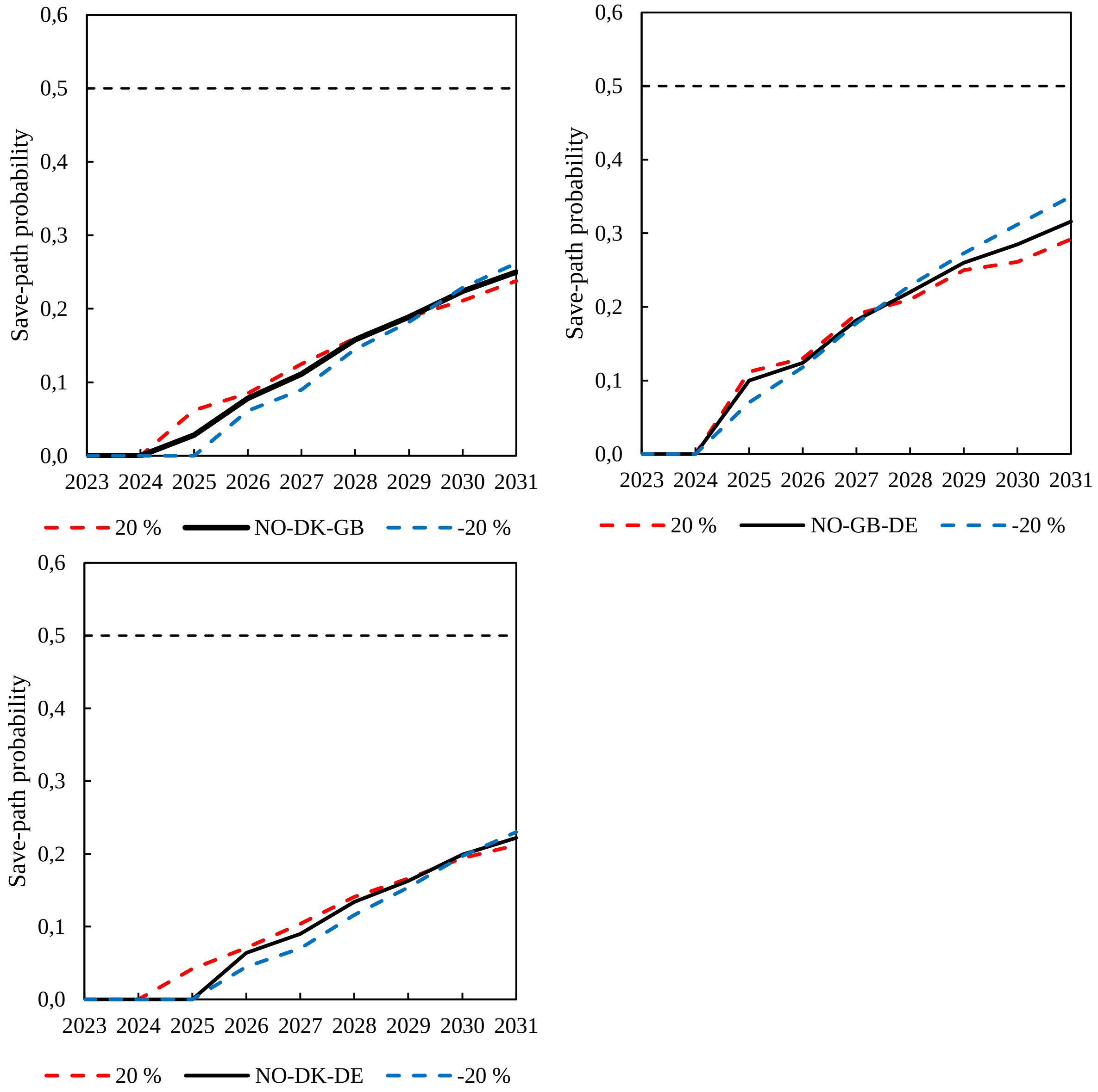

Figure 21: Save-path probability the OWP project under a radial and three-market hybrid grid configuration using the ROV method for a 20% increase and decrease in volatility.

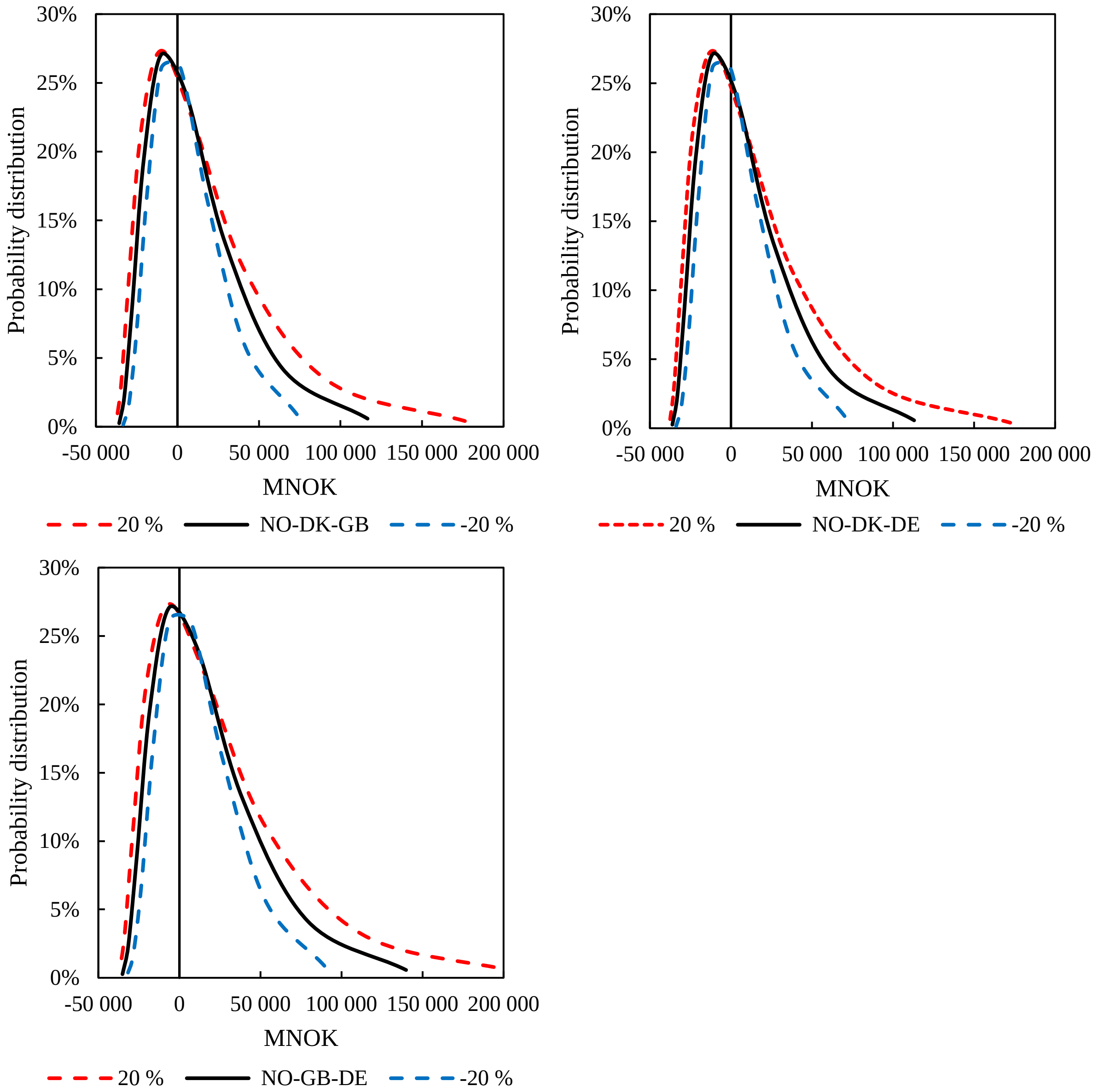

Figure 22: Probability distribution of the OWP project value in 2031 for radial and three-market hybrid configurations with an 20% increase and decrease in electricity price volatility.

Norges miljø- og biovitenskapelige universitet
Noregs miljø- og biovitskapelege universitet
Norwegian University of Life Sciences

Postboks 5003
NO-1432 Ås
Norway