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An economical assessment of electrifying offshore oil and gas installations: A path-dependent real options approach

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Preface

This Master's thesis marks the end of my degree within Industrial Economics and Technology Management, with a specialization in Investment, Finance and Cost Control. The paper is a continuation of the work done in my project specialization "The Option to Electrify Offshore Installation", written during the spring of 2021.

My starting point when deciding on a topic for both the project specialization and this Master's thesis was that I wanted to spend the final year investigating investment decisions that might be of a similar nature to problems I will be faced with throughout my career. With me set to enter into a project planning position in the energy industry, these two papers have given me an introduction into the many challenges of making long term investments and the array of considerations that must be made before making such investment decisions.

This paper is written in collaboration with a leading operator on the Norwegian continental shelf, who have contributed with data input and provided a real life case of an operative oil and gas installation. This has brought an industry perspective to the thesis and allowed the paper to be shaped in accordance with the challenges they are faced with.

Furthermore, I would like to thank Dr. Pedro Crespo del Granado for valuable guidance over the past 10 months. He has provided an understanding of the complex and uncertain future facing the energy industry over the next 30 years. His insight within the intricacies of the carbon market and development of new technologies has greatly shaped the approach in this paper. Finally, a big thanks to Dr. Steffen J. Bakker for being proactive and providing continuous guidance. The model in this thesis could not have been developed without his eagerness to help and insight on stochastic programming. The applied methodology is largely inspired by his previous work, and by never being further than a teams call away, he has provided the help needed to drive the paper forward.

Trondheim, October 2021

Odin Strømberg

Summary

Operations on offshore oil and gas (O&G) platforms on the Norwegian continental shelf emit considerable amounts of CO_2 emissions. To reduce this amount, replacing the traditional power generation relying on gas turbines with supplied electricity has been considered an effective solution. Historically, such electrification has been done through supplying power from the onshore grid, but more recently initiated projects are attempting to power platforms using electricity from nearby offshore wind farms. In this thesis, we consider both options when investigating the economical feasibility of investing in electrification of offshore O&G platforms.

Specifically, we target the problem of making investment decisions on a real life offshore installation, where the operator is currently considering electrification measures. As such, our research questions are as follows:
Which market conditions are required for profitable investments in electrification of O&G installations?
Will the optimal investment strategy be affected by also including an option to export power generated from offshore wind to shore after the lifetime of the O&G field?

We formulate this as a multistage stochastic integer programming problem with an objective to maximize the expected NPV, by choosing the optimal decisions and investment timing. The three path-dependent options available to the decision makers are

- Invest in importing power from shore to offshore installations
- Invest in an offshore wind farm to power offshore installations
- Invest in exporting power to shore from an offshore wind farm

The options are not restricted by each other, but their costs may depend on previous investments. Following Luehrman (1998)'s definition of strategy as a portfolio of real options, we aim to make the optimal strategic decisions by regarding the problem in a real options setting. We allow for uncertainty in the wholesale electricity price and apply the stochastic dual dynamic integer programming algorithm to obtain recommended decisions for each realization of the uncertain process. The literature review finds that valuation of electrification projects to a large extent relies on traditional project valuation methods. To the author's knowledge, we therefore provide a research contribution by being the first to consider a real options approach to an electrification problem allowing for power from shore and offshore wind. In addition, we also provide a recommended course of action for the operator of the field. This is summarized in the findings for the considered case study below.

- We find a recommendation to invest in a 100MW offshore wind farm in 2026. For this investment, we can be 90% confident that the expected NPV is in a region of [1423, 1673] million NOK.
- Our simulation study considers 1000 scenarios, where we obtain a suggested decision for each realizations of the uncertain electricity price. 92,3% of simulations advised for investing in offshore wind for electrification. An additional 6,6% gave the same recommendation, but also advised for exporting electricity after the field's lifetime. Finally, only 1,1% found investments in power from shore to be the optimal choice.
- Increasing volatility in the electricity price gave higher expected profitability, as well as an increasing shift from recommending electrification using offshore wind to power from shore. However, it did not lead to later investment timing.
- The potential savings in carbon costs from electrification are found to be the most dominant contributor to the cash flows. We therefore find increasing carbon charges as the most determining market factor for the profitability of electrification projects.
- Further analysis found the immaturity of technology of floating wind turbines to be decisive in both investment timing and profitability of the investment.

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Nomenclature

CAPEX Capital Expenditures

CO_2 Carbon dioxide

DCF Discounted Cash Flows

GBM Geometric Brownian Motion

GT Gas turbines

HSE Health, Safety and Environment

MSIP Multi-Stage Stochastic Integer Programming

NOK/TC NOK per tonne CO2

NOx Nitrogen oxides

NPV Net Present Value

OPEX Operational Expenditures

OWF Offshore Wind Farm

PFS Power from shore

RO Real Options

ROA Real Options Approach

SDDiP Stochastic Dual Dynamic Integer Programming

1 Introduction

Through the goals set in the Paris agreement, Norway has committed to reducing 40% of their CO_2 emissions, with an intent to increase this to 50% compared to a 1990 reference level. With such ambitious goals, the attention is turned to oil and gas (O&G) extraction processes on the Norwegian continental shelf, which contributes to approximately 28% of the national emissions of greenhouse gases (Statistics Norway, 2021). The processing of the extracted hydrocarbons offshore is energy intensive and this energy is usually supplied from the burning of O&G in turbines offshore. Of the total emissions from the petroleum sector, approximately 85% stem from the burning of natural gas or diesel in these turbines (The Norwegian Petroleum Directorate, 2020).

For over two decades, offshore emissions have been reduced by supplying power from the onshore grid to offshore installations. Such electrification is characterized by large investment costs due to the challenges of installing cables over large distances. More recently, projects have been initiated aiming to supply the power through offshore wind farms. For the latter, there is significant uncertainty about future cost developments and the feasibility of operating at remote locations in deep waters. In addition, the profitability of electrification projects depend on market uncertainties. Increasing CO_2 taxation levels will incentivize emission reducing measures, while an increase in electricity prices can make supplied power more expensive. Finally, the hydrocarbons not combusted are available for export and will be subject to price uncertainty as well. The complexity of the problem becomes even greater when considering political uncertainty, which may affect subsidies and taxation levels. This thesis is not intended to accurately handle all these parameters, but aims to investigate parts of this uncertain future and thus provide a recommendation for which strategic decisions should be made to ensure profitability of electrification projects.

Given these challenges, we aim to establish which market conditions are required to make profitable investments in electrification of offshore O&G installations. In addition, we investigate whether the optimal investment strategy is affected by dependencies between the considered options. Specifically, we consider electrification using power from shore and/or offshore wind, as well as allowing for power from wind turbines to be exported to shore beyond the expected lifetime of the O&G fields.

This thesis is a continuation of my project specialization written in the spring of 2021, where an investment in electrification using power from shore was evaluated based on discounting the net present value (NPV) of the project. The extensions in the model setup in this thesis are as follows.

- Allowing for uncertainty in the electricity price.
- Development of a real options approach based on principles of stochastic dual dynamic integer programming.
- Inclusion of the option to electrify using power generated from an offshore wind farm.
- Inclusion of the option to export wind-generated power to shore beyond the field's lifetime.

Furthermore, the approach applied in this paper draws inspiration from the one taken in (Bakker et al., 2021), where complex interdependent real options are formulated based multi-stage stochastic integer programming and efficiently solved using stochastic dual dynamic integer programming. We apply a similar approach to investigate the interplay between three investment opportunities over a period of 30 years, to provide a recommendation for the investment decision to be taken today. With an objective of maximizing the NPV, we use Monte Carlo simulations to investigate 1000 electricity price developments and obtain a suggested strategic decision for each.

Our main stochastic element is the price of wholesale electricity, but this paper also places great emphasis on the role of carbon pricing. An expected increase in carbon charges are seen as an important motivation for industrial actors to initiate electrification, and we therefore investigate the effect of several future scenarios of CO_2 pricing. These scenarios rests on assumption of varying degrees of political involvement and societal developments, and based on this we aim to establish the conditions required for profitable electrification.

An extensive literature review revealed that for evaluations of the economical feasibility of electrification projects, there is a clear tendency towards applying deterministic price forecasts. Our setup with NPV calculations is to a large extent similar to the approaches taken in (Riboldi et al., 2017) and (Riboldi et al., 2019). However, the inclusion of elements from real option theory with an uncertain electricity price process and dynamic programming means there are also similarities with (Cowell, 2014). There are however important points of differentiation between the latter and this thesis. The first being that we include options to electrify using offshore wind and export power to shore beyond the field's lifetime. Secondly, whereas they consider an expansion option from previously installed electrification infrastructure, our setup has no such previous instalments, which changes the dynamics of the investment costs. Moreover, previous electrification works often consider the effect of uncertain futures through scenario or sensitivity analysis. Similarly to (Cheng et al., 2017), we also apply various scenarios of carbon prices, but with significantly higher price trajectories. No previous literature on applying real options to evaluate electrification with offshore wind was identified. We therefore view the application of such an approach to not only have potential value for decision makers, but also to contribute to the literature within this field. Furthermore, we aim to provide an additional contribution by evaluating the overall potential of applying real options in this context.

The remainder of this paper is structured as follows. We first present background information on electrification in section 2. Then, section 3 presents a literature review on project valuation methods and of previous works assessing electrification. The problem description is laid out in section 4, before the mathematical formulation of our model is given in section 5. We then present how uncertainties in the electricity price are handled in section 6, before giving an introduction to our real life case study in section 7. Results and following discussions are presented in section 8. Finally, concluding remarks are given in section 9, before we discuss future research in section 10.

2 Background

In this section, we aim to provide an understanding of the many challenges related to making investments in electrification projects. First, we introduce electrification and how it has been implemented on the Norwegian continental shelf (NCS). This is followed by a discussion on important aspects of the investment conditions for decisions makers of such projects. Finally, we provide a brief introduction of market conditions that may affect the decision to invest.

2.1 Electrification of the NCS

The motivation for initiating electrification projects is to reduce the emissions of greenhouse gases (GHG) from offshore processes. Operations within the petroleum sector contributes to approximately 28% of the national emissions of GHG (Statistics Norway, 2021). The distribution of these emissions are illustrated in figure 1, where we observe that approximately 85% of the total emissions stem from the burning of natural gas or diesel in gas turbines (GT) (The Norwegian Petroleum Directorate, 2020).

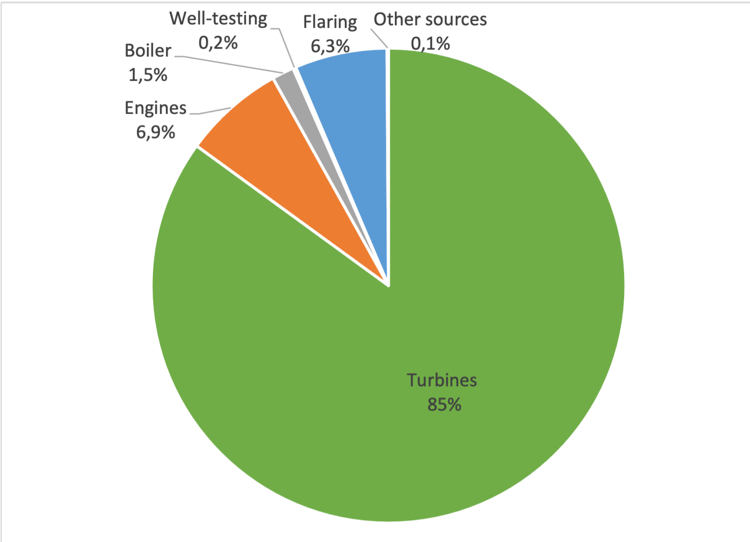


Figure 1: The distribution of greenhouse gas emissions from the petroleum sector on the NCS. Image recreated from graph in (The Norwegian Petroleum Directorate, 2020)

By replacing these GT with alternative power sources, there may be considerable emission reductions of CO_2 and nitrogen oxides (NOx). One approach is electrification, which refers to the process of replacing the traditional power generation with supplied electricity. This is usually done by providing power from shore (PFS) to offshore O&G installations, but can also be done using power generated from nearby offshore wind farms (OWF). PFS is supplied using subsea cables transported over large distances, which may affect the onshore grid's supply security due to increased power consumption. This is not the case for electrification using OW, but there are still challenges in supply security in times of unfavorable wind conditions.

Electrification Using Power From Shore

The first offshore installation to be supplied with PFS on the NCS was Troll A in 1996. The amount has increased since, with 16 fields either in operation or expected to be in 2023 (The Norwegian Petroleum Directorate, 2020). Of these, a very notable case is the the Johan Sverdrup field located at the Utsira High area and shown in figure 2. The reductions in emissions can be illustrated by studying the amount of CO_2 emissions per barrel of oil produced. Johan Sverdrup operates with 0,67 kg CO_2 per barrel, whilst the average on the NCS is 9kg and the global average is 18 kg per barrel (Equinor, 2021a). This large reduction is also caused by technological improvements, but electrification is the main contributor. An important clarification when assessing a case such

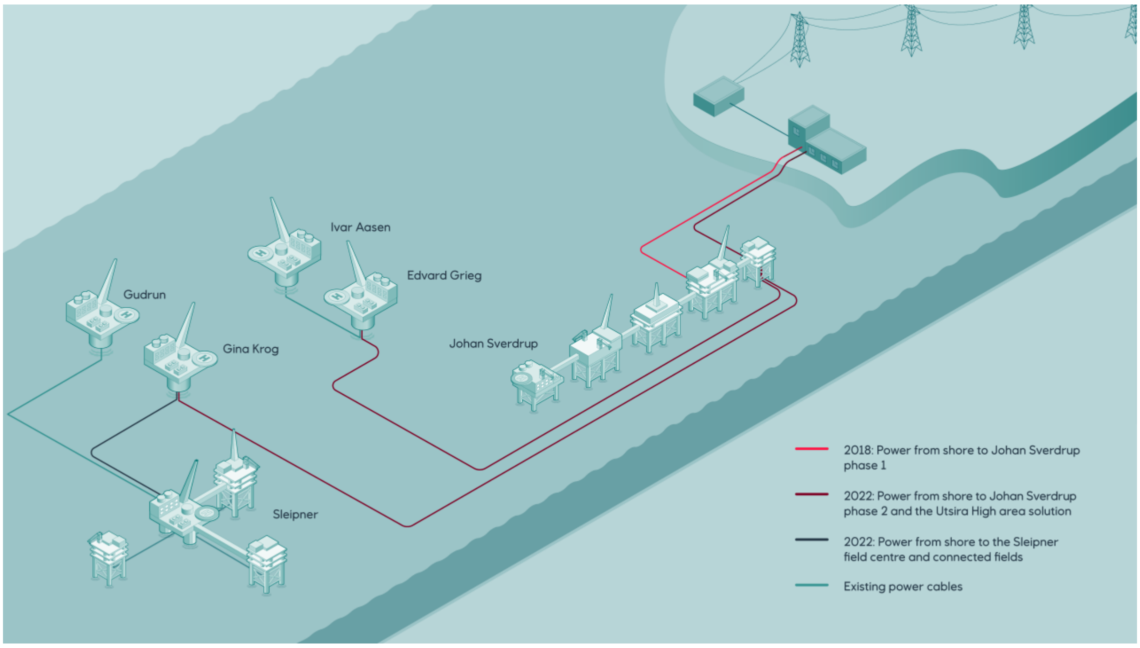


Figure 2: Illustration of electricity supplied from the onshore grid to the Johan Sverdrup field and the Utsira High area. Image from (Equinor, 2021a)

as Johan Sverdrup is the fact that electrification using PFS was implemented in the first phase of the development plans. Existing installations already powered by GT needs to be modified to receive PFS. This is usually significantly more costly than dimensioning new installations for electrification. Another element is the possibility of an area solution, where several fields may be connected to the same power supply. This may result in lower investment costs than if each field would implement their own solution, and therefore represent advantages due to economies of scale.

Electrification Using Power From Offshore Wind

Furthermore, electrification may also be accomplished by integrating an OWF with existing platforms. A prominent example is the Hywind Tampen project, set to become the world's largest floating wind farm. Due to start up in 2022 with a power generation capacity of 88MW, it will supply an estimated 35% of the power demanded at the Snorre and Gullfaks fields in the North Sea (Equinor, 2021b). It is labelled a test bed for further development of floating wind turbines, and with significant funding through ENOVA (2,3 billion NOK) there is a hope and expectancy that the experience from the project may help reduce costs and provide knowledge for future projects.

Two significant advantages of electrifying using offshore wind (OW) compared to PFS are the lack of power transmission over large distances and an assurance that the power source is renewable. Although Norway's power generation mix is approximately 90% hydrobased, with the remaining portion being almost entirely supplied by wind-power (NVE, 2021), they are interconnected with a European network that relies on fossil fueled power plants (Ministry of Petroleum and Energy, 2020). Therefore, critics of PFS solutions argue that the increase in offshore power demand may lead to increased power generation from CO_2 emitting sources, thus offsetting the offshore reductions. Through many years of experience, the Norwegian O&G industry have set great Health, Safety and Environment (HSE) standards. Due to variability in wind conditions, having a platform's power demand entirely supplied by an OWF would represent an HSE risk for personnel, as well as operational challenges under unfavorable wind conditions. Although there is a risk in terms of supply security from transmission issues, PFS can be viewed as a more stable power source. Under good wind conditions there may be production close to the capacity, but the platform's power demand must rely on other sources when the wind is not blowing. We incorporate this effect in the calculations by including a capacity factor, which is the average power output from the wind turbines divided by its maximum power producing capability (University of Michigan, 2020).

The main types of OW configurations are either bottom-fixed or floating wind turbines. Bottom-fixed can be used for depths until 50m, while for deeper conditions floating wind must be used (Equinor, 2019). Given that many O&G fields have depths considerably larger than 50m, we consider floating wind turbines for electrification in this paper. With the Hywind Tampen project being labelled a test bed, there is an expectation that learning effects will reduce costs of similar projects over the field's lifetime. This is also a common assumption for floating OW in general, which can be seen in figure 3. Here, the levelized cost of energy decreases from around 135 EUR/MWh to less than 50 EUR/MWh in 2050 and the graph also indicates a steeper learning curve for floating compared to bottom-fixed wind turbines.

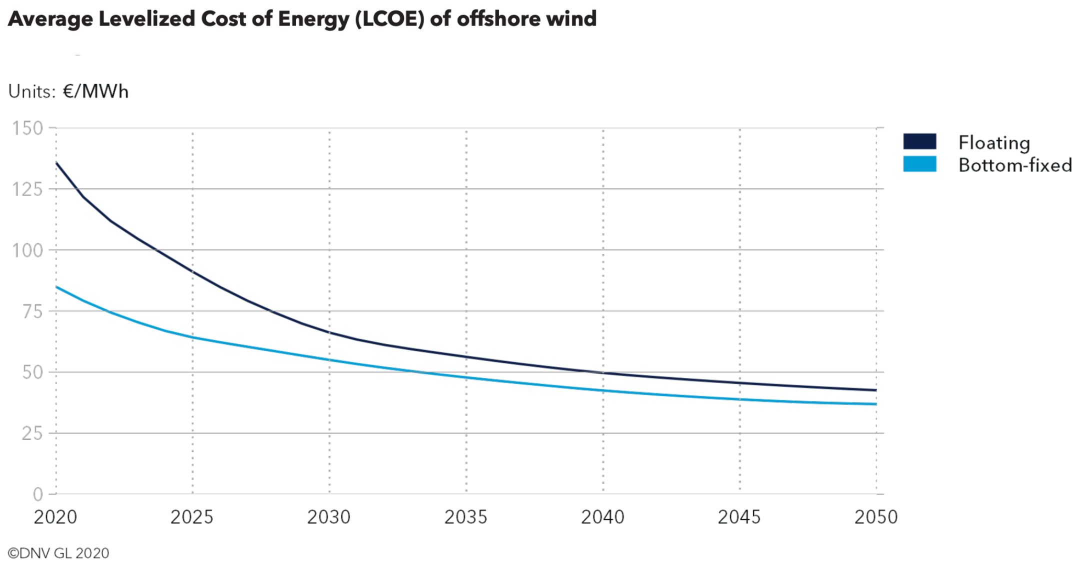


Figure 3: Cost-learning curves per unit of power output over time from offshore wind. Image from (DNV GL, 2020)

2.2 Investment Conditions for Electrification Projects

In this subsection, we highlight that operators of O&G fields must consider more than just the profitability of investment before taking on electrification projects. We discuss the role of political actors, present some criticism against electrification and differentiate between taking a socioeconomic and business economic perspective to the investment decision.

2.2.1 Criticism of Electrifying Platforms

The motivation behind electrification investments is to reduce GHG emissions. Given the large scale of these projects and potential implications for the onshore power grid, significant political involvement is expected. Norway have committed to reducing GHG emissions by at least 40% within 2030 and between 80-95% within 2050 compared to the 1990 reference level (Ministry of Climate and Environment, 2021b). Thus, by reducing the burning of hydrocarbons on the NCS and exporting it to Europe there may be a significant improvement on Norway's emissions. This has been met with criticism as the gas will be combusted in other countries. As the climate crisis is a global one, political opposition to further electrification has branded it as "symbolic politics" as it appears as an environmentally friendly alternative, but globally its contribution may be less significant (Saudland et al., 2021). However, burning coal to produce energy releases more GHG (Catuti et al., 2019), and if the exported natural gas displaces this, there can be a reduction of emissions. Another important term is GT efficiency, which can be viewed as the percentage of how much of the energy from the fuel gas is converted into electricity. Therefore, with higher efficiency there will generally be less emissions per unit of electricity produced. There are many ways to increase GT efficiency, but given space, weight and capacity restrictions on offshore platforms such improvements are more easily made on onshore industrial power plants. These may operate with efficiencies in the region of 50-60%, while offshore GT are operating around 25-35% (Tahir, 2021). More energy efficient utilization of the fuel gas onshore is therefore an important motivation for wanting to electrify platforms.

It becomes apparent that to uncover the total environmental effect, we must consider more than the reductions in CO_2 emissions from removing offshore GT. Such a consideration may implicitly assume that all supplied electricity is produced without emissions, few losses in both supplied electricity and exported gas and finally that the natural gas can displace more GHG emitting alternatives. These assumptions are not necessarily valid, especially as the Norwegian power grid is connected with other European countries. Another important element of the problem is the finite nature of O&G fields. Several installations on the NCS are producing from mature fields, experiencing production decay and using ageing infrastructure (Santibanez-Borda et al., 2021). As a result, there is limited time available to collect the benefits from electrification, which can make it difficult to justify the investment cost.

2.2.2 Socioeconomic and Business Economic Perspectives

Osmundsen (2012) discusses that the problem of electrifying can be seen from different perspectives. From a business economic, companies will take on projects if they are deemed profitable and the NPV of expected cash flows is positive. The valuation is different from a socioeconomic perspective, as is the case for several governmental reports on emission reducing measures. This is the perspective taken in both (The Norwegian Petroleum Directorate, 2020) and (Ministry of Climate and Environment, 2020), where projects are evaluated in NOK per ton CO_2 removed. These are referred to as measure costs and are labelled as the socioeconomic cost of the project. Although governmental actors may want to pursue projects minimizing the measure cost, industrial actors may have an overall objective of taking on profitable investment. The two are not necessarily mutually exclusive, but the differences in objectives may lead to dissimilar willingness to initiate projects. For this thesis, we will mainly focus on the profitability from a business economic perspective. However, given the high degree of political involvement in these projects, both perspectives are relevant for the decision makers.

2.3 Market and Price Considerations

In addition to political influences, the investment decision is also subject to market uncertainties. In this subsection, we present aspects of carbon and electricity prices that are likely to be relevant for electrification projects. These will be elaborated on when data input for our case study is presented, but important attributes and characteristics are given here. In addition, prices of natural gas and cost of NOx are also relevant, but are not elaborated on here.

Carbon Price

In January 2021, the Norwegian government published their "Climate action plan 2021-2030", where a notable goal was to have a carbon tax rate of 2000 NOK per tonne CO_2 [NOK/TC] equivalents in 2030, compared to approximately 590 NOK/TC at that time (Ministry of Climate and Environment, 2021a). This charge includes the EU Emission Trading System (EU ETS) quotation system, which Norway are a part of. A main element of this system is to place a ceiling on the amount of CO_2 equivalents that can be emitted, with these quotations available for trading. This ceiling will reduce over time to ensure emission reductions, which will subsequently make it more expensive to keep emitting GHG. This is to work as an incentive for companies and industries to reduce their emissions (EU, 2021). The Norwegian charge therefore includes an additional tax rate if the EU ETS value is below the Norwegian targets (The Norwegian Petroleum Directorate, 2020). Although this may indicate a situation where companies subject to the Norwegian tax level are less subject to market changes, there are still uncertain factors to be considered. There is political willingness in Norway for a close cooperation with the EU in tackling climate change (The Norwegian Government, 2021), meaning the level of 2000 NOK/TC may be subject to influences from the EU. On the other hand, the Central Party, which are set to enter into a new Norwegian government, have clear intentions of renegotiating the EEA agreement (The Centre Party, 2021), which to a large extent dictates Norway's role in the EU ETS system. The goal of this thesis is not to delve into the political landscape surrounding CO_2 reducing measures, but to highlight that there is still significant uncertainty related to the carbon price development. An historical development of the carbon market price in the EU ETS are obtained from (Sandbag, 2021) and shown in figure 4, where prices are given as EUR/TC.

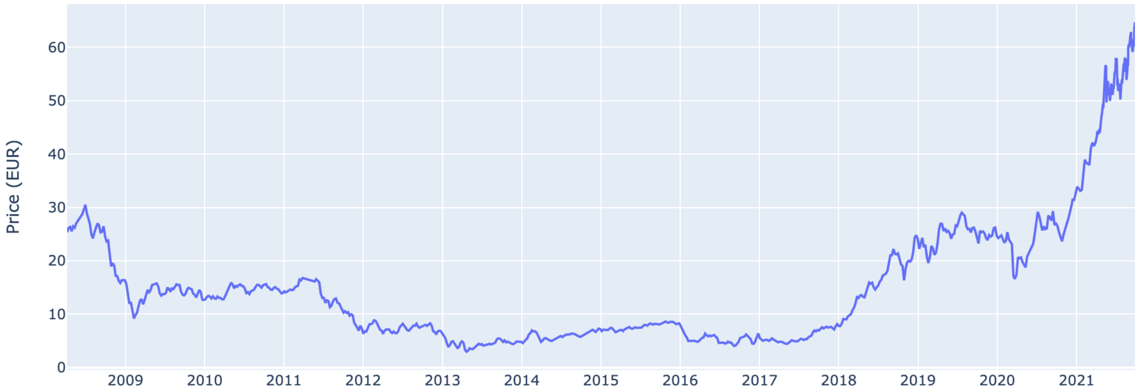
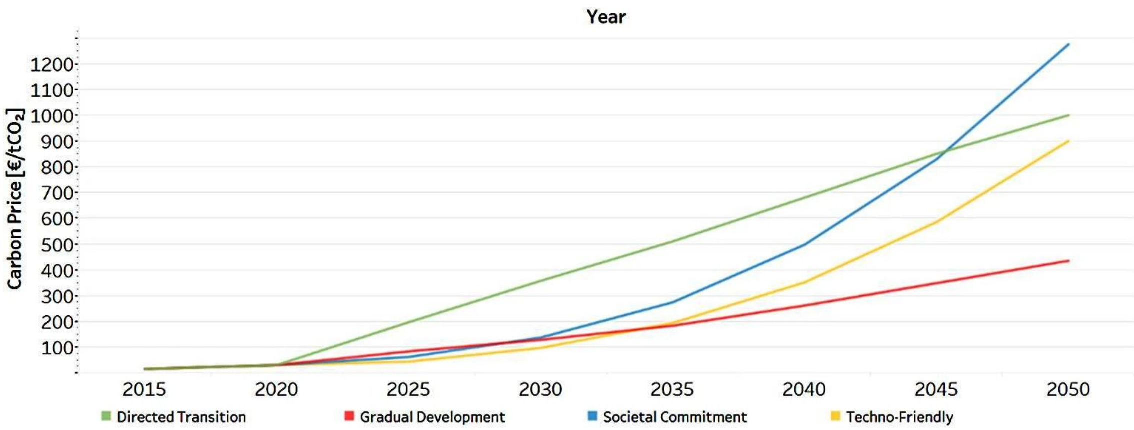


Figure 4: Historical carbon market price in the EU ETS. Image from (Sandbag, 2021)

An indication of the uncertain tendencies in the carbon price are seen in figure 4, where we observe an historically high level and steep increase in 2020-2021. Such an increase is in line with the development needed for the Norwegian charges to reach the 2000 NOK/TC level in 2030. As this thesis considers an electrification problem in a long-term perspective, estimates of future developments of the carbon price will be useful. Such trajectories have been established in (Auer et al., 2020), where the carbon price for four scenarios reflecting a low-carbon society in accordance with the global 1,5°C and 2°C increase goals established in the Paris agreement (United Nations, 2021). Each scenario is based on assumptions of actions that are required to reach these targets and are shown in figure 5. Compared to the historical levels in figure 4, a substantial increase is observed. Three of them are accounting for scenarios where the 1,5°C goal is met, while the gradual development (red curve) approaches the 2°C target.



Pathway	2015	2020	2025	2030	2035	2040	2045	2050
Directed Transition	15	30	196	357	510	680	850	1,000
Gradual Development	15	30	83	128	183	261	348	435
Societal Commitment	15	30	62	137	273	497	829	1,275
Techno-Friendly	15	30	43	97	193	351	585	900

Figure 5: Illustrating Carbon Price development until 2050 for suggested scenarios reflecting a low-carbon society. Image from (Auer et al., 2020)

With the potential savings in offshore CO_2 emissions from electrifying platforms, increasing CO_2 charges can contribute to increased profitability of such projects. The combination of the EU

ETS quotations being traded assets subject to market uncertainties and political changes, suggests that the situation might be more complex than having a gradual increase towards 2000 NOK/TC in 2030. Although Norway have established a target level in 2030, the situation beyond is less apparent. Appropriate handling of the carbon price therefore becomes an important step towards making well informed decisions on electrification projects and will therefore be a focus area in this paper.

Electricity Price

An argument used against platform electrification with PFS is that increased power consumption may lead to a price increase for the onshore consumers of electricity. An increase in market prices may not only make the supplied power more expensive, but can also influence societal opinion, which may affect policy maker's willingness to support projects. The market for electricity is based on principles where electricity production and trading are market based, while grid operations are strictly regulated (Ministry of Petroleum and Energy, 2020). Furthermore, we can divide the market into wholesale and end-user market. In the end-user, individual consumers enter into agreements to purchase electricity from a chosen supplier. In the wholesale market, large volumes are bought and sold by industrial actors, energy companies, power producers etc. This market is further divided into Statnett's balancing market, as well as day-ahead and continuous intraday markets. The two latter ones are both traded on the Nord Pool exchange. As we are interested in the cost of electricity from the perspective of an industrial actor, we focus on the wholesale market, with input data based on day-ahead prices.

This section has provided background information that will be relevant for the remainder of this thesis. We have introduced different ways to electrify offshore installations, presented criticism of electrification and highlighted the differences in taking a socioeconomic and business economic perspective in this context. Finally, we have introduced relevant market prices, with a particular focus on carbon pricing. In light of the presented information, we will investigate the following research questions:

- Which market conditions are required to make profitable investments in electrification of offshore O&G installations?
- Will the optimal investment strategy for electrification projects be affected by including the possibility of exporting wind-produced power to shore beyond the O&G field's lifetime?

3 Literature Review

In this section, we aim to position this thesis in the existing body of literature on electrification of offshore O&G installations. First, the applied literature search strategy is presented. This is followed by introducing relevant theory on project valuation methods, with a particular focus on taking a real options approach (ROA) to evaluate investment opportunities. We then provide literature references to works that have applied a ROA to investments in OW under uncertainty. This is followed by an extensive overview of the available literature on electrification of offshore installations, which will be used to position this thesis in relation to previous works. Finally, we present this thesis' potential for research contribution and identified literature gaps.

3.1 Literature Search Strategy

This subsection will provide an insight into the approach taken to discover previous knowledge on topics related to the formulated research questions. The main tool for literature search has been Google Scholar, but also through Oria for works conducted by researchers at NTNU. Given the interest in electrification, relevant literature have been found through different combinations of the following keywords:

<Electrification>, <Offshore>, <Platforms>, <Oil and Gas>, <Offshore wind>, <Power from shore>

With an interest in investment analysis and project valuation, these have often been supplemented with keywords for valuation methods:

<Investment>, <Real Options>, <Price uncertainty>, <Cost analysis>, <NPV>, <Optimization model>

Our main criteria for assessing previous works have been journal relevance and impact on literature. For the former, the interest in the above-mentioned keywords have narrowed the focus on journals considering energy processes and investments, particularly within renewables. The identified literature have been published across a range of journals, but works published in *Applied Energy*, *Energy Procedia* and *Renewable and Sustainable Energy Reviews* have been especially important in shaping this chapter.

Furthermore, an advantage of using Google Scholar is the available citation metric. This has allowed us to select papers based on their impact in the literature. In addition, the search engine allows for computing a further search within the citing articles of selected papers. This provides an opportunity to identify works that have conducted further research on the same topic. This method is a way of looking forward in the literature, but by studying literature reviews of identified papers, we have also been able to work backwards. Such an approach gives insight into how previous works have attempted to fill literature gaps and is also useful in identifying works building on similar setups. This has provides an impression of how the knowledge within the field has developed over time.

3.2 Project Valuation Methods

In this subsection, we present methods for valuing projects or investment opportunities. Specifically, we aim to differentiate between traditional approaches relying on NPV with discounted cash flows (DCF) and applying a ROA to evaluate investments. Although the traditional methods are renowned and widely utilized, we reference literature discussing how a ROA may provide a more appropriate framework for handling the complexities of real life investments.

3.2.1 Neoclassical Approach

To quantify the true economical cost of a real project, both technical and financial risks must be considered. When faced with such uncertainties, investors and decision makers attempt to predict the value of capital investment projects and select those with highest potential returns consistent with the project risk profile. Due to its simplicity, the most widely used project valuation technique for investments is using DCF to calculate the NPV (Espinoza and Morris, 2013). The rule of investing if the NPV of a project's expected returns is positive is referred to as the neoclassical investment rule and is labelled a pillar of modern finance (Anderson, 2012). Similarly, the internal rate of return (IRR) and payback methods are also widely applied and fall under this category of project valuation methods. NPV calculations are commonly integrated in optimization models that account for operational constraints. These may have objectives of minimizing costs or maximizing profitability, and are often found within evaluation of O&G projects, as well as renewables. Examples of deterministic models maximizing NPV of projects concerned with planning the infrastructure in offshore oil fields are found in (Carvalho and Pinto, 2006) and (Gupta and Grossmann, 2012), using MILP[1] and MINLP respectively.

3.2.2 Real Options Approach

Although incredibly widespread and utilized across numerous disciplines, using the NPV method with DCF for investment decisions has faced criticism. Prominently, Dixit and Pindyck (1994) argues that this approach implicitly assumes that investments are reversible, and in the case of irreversible investments, the decision is "now-or-never". They argue that the ability to delay and await more information before making irreversible investments can be incredibly important for making profitable decisions. To include these attributes when making investment decisions in the face of uncertainty, they present a ROA, where optimal investment rules can be obtained using methods developed for pricing options in the financial market. Since their work, RO theory have been widely applied in project valuation, where decision makers wish to determine their optimal strategy. This can be applied to investment options entitling the decision maker to future cash flows, but also to investigate halting, abandonment or expansion of projects as market conditions change. Compared to traditional NPV analysis, Leslie and Michaels (1997) claim that a ROA offers a more comprehensive valuation as it includes the value of flexibility. This flexibility can be described as the expected value of the change in NPV over the option's lifetime. Following the analogy between financial call options and real life investments, increased uncertainty will also increase the value of the option to invest (Kandel and Pearson, 2002).

The challenges of investing in renewable energy generation projects with conventional DCF methods are investigated by Martínez-Ceseña and Mutale (2011), who believes the value may be increased when a ROA is used for planning and evaluation of such projects. The reasons for this may be the conventional approach's inability to handle uncertainties regarding the renewable source, electricity price and technology. When applied to a case of investing in hydropower, the RO methodology gave higher expected profits than the DCF approach. It is noted that in the absence of all flexibility, a ROA would behave similarly to traditional NPV calculations. This paper is mentioned in an extensive literature review of the use of RO for evaluating investments in the energy sector by Fernandes et al. (2011). They focus on how investment decisions in projects using renewable energy sources may be evaluated as not cost-efficient compared to other projects. It is claimed that traditional methods fail to assess the strategic dimensions of such investments and do not handle risk and uncertainty of such projects properly. Some of the uncertainties identified in investment projects considering renewable energy sources are listed below:

- Variability of natural sources, such as wind speed
- Possible changes in support schemes
- Steep learning curves within technological advances

[1]MILP(Mixed Integer Linear Programming. MINLP - Mixed Integer Non Linear Programming)

- Prices of fossil fuels
- Electricity prices

Luehrman (1998) describes strategy as a portfolio of real options. It is claimed that business strategy is a series of options, where some actions are taken immediately, while others are deliberately deferred so that managers can optimize as circumstances evolve. Such a portfolio of options can also be found in the context of financial options, where the underlying security is another option, and we may have several strike prices and expiration dates (McDonald, 2013). Translated into a RO setting, Loncar et al. (2017) examine compound path-dependent options, where the sequential nature of the options meant RO theory could be used to examine abandonment, expansion and other operational choices. The idea of compounded options can also be found where one investment leads to different conditions for other future investments, thus becoming path-dependent. In the context of this thesis, this understanding of compounded RO is applied.

3.3 Project Valuation of Offshore Wind Investments

In the previous subsection, we presented why taking a ROA to investments in renewables can be beneficial for accurate project valuation. Given the potential for platform electrification using OW, this subsection will narrow the focus down to papers that have taken such an approach to investments in OW. The target is not to provide a complete overview of the use of RO within OW or identify literature gaps, but rather to provide some examples of where it has been applied and to present the handling of uncertain elements in these works.

The literature considered in this subsection differs in who they claim can draw advantage of their project valuation methods. Several works focus on providing a tool for making the most profitable decisions for investors, while others emphasize that their results are useful for policy makers in drafting efficient legal framework. Kitzing et al. (2017) claim their findings are useful for both when they apply a ROA to analyse wind energy investment under different support schemes. Uncertainties in power price and wind speed are considered for a case study on OW. Several correlated uncertainty factors are combined into a single stochastic process, which is solved analytically. Furthermore, Li et al. (2019) takes the perspective of policy makers and apply a ROA to establish the optimal Feed-In-Tariff level for incentivizing investments in OW. Here, the intermittence of renewables (e.g. wind speed) and technology learning are treated stochastically whilst using dynamic programming.

Another interesting perspective within this subject is found in (Iniesta and Barroso, 2015), where it is identified that most examples of using RO as a valuation tool only consider the project promoter's options. They claim this causes a valuation bias, as there also exists regulatory real options (RRO) held by authorities through their regulatory framework. Such RRO are identified and their effect on OW investments in Denmark are evaluated by considering a variety of uncertainties. These are investment cost, electricity price, consumer price index and power produced, and are used to find that the RRO decreases the value of OW investments. The focus is entirely shifted towards the investors in (Kim et al., 2018), who proposes a decision-making model using a ROA to assess the economic feasibility of OW power projects. They consider uncertainty by using a variety of scenarios for climate change and their resulting effect on wind conditions.

Furthermore, Fuss and Szolgayová (2010) find that applying a ROA to an OW investment indicated that the uncertainty associated with the technological progress leads to a postponement of investment. To assess the OW farm, they allow for uncertainty in technological change by modelling innovation through a Poisson process, where the average arrival rates of innovation determines the magnitude of technological improvement. Such assumptions of technological improvements are critiqued by (Schwanitz and Wierling, 2016), who claims that over-optimistic assumptions for projections of investment costs give flawed project valuations. They add that the growing complexity of larger wind farm projects may in fact result in a negative learning trend. Via a controlled diffusion process, technical and input cost uncertainty are considered. Using a ROA, it is concluded that it is not likely that OW investment costs will decrease in the near future.

In conclusion, this subsection has shown that RO approaches have previously been applied to OW investment to handle a variety of uncertain factors. In the next section, we will provide an extensive overview of the literature on electrification. There, it will become apparent that although RO have been applied for OW investments, there exists a gap in terms of applying it to electrification using OW and very limited applications for valuing projects involving electrification of offshore installations in general.

3.4 Electrification of Offshore O&G Installations

There exists a large body of literature on electrifying O&G platforms. This subsection therefore aims to categorize this body, so that this thesis can be positioned appropriately. To do so, table 1 presents a list of differentiation criteria, which are applied to the identified works. Literature on electrification with PFS are presented in table 2 and using OW, both or other power sources in table 3. Finally, we expand on the most important works presented in these tables and discuss different perspectives taken to evaluate electrification problems.

Differentiation Criteria	**Explanation**
Economical evaluation	This category represents whether there are cost calculations. If there is, an indication will be given as to how its done. This may be through NPV calculations using DCF or by assessing a project through the LCOE.
CO_2 evaluation	This category aims to differentiate between how papers treat the reductions of emissions. Therefore, the different approaches are categorized as 0,1 and 2 according to the following criteria: **0:** No accounting for emission reductions. **1:** Accounts for emission reductions from hydrocarbons not burned in offshore GT. **2:** Accounts for emission reductions from hydrocarbons not burned in GT, but also includes emissions related to the new power alternative. Usually, this will be emissions related to the onshore grid's response to an increase in the power demanded offshore.
Uncertainty handling	This section will describe whether or not there is any uncertainty handling in the paper. Often this will be through analyzing the effect of different future scenarios or through sensitivity analysis.
Power source	This category describes the power source for electrification. Either through PFS, OW, both or others.

Table 1: Explanation of differentiation criteria for literature on electrification

With the differentiation criteria established, the next step is applying them to the identified works. The results for literature on electrification with PFS are found in table 2, whilst table 3 considers works applying OW, a combination or other power sources.

Paper	CO_2 Evaluation	Uncertainty Handling	Power Source	Cost Calculations
Riboldi et al. (2019)	2	Three future scenarios for fuel and CO_2 prices	PFS	NPV
Cheng et al. (2017)	2	Three CO_2 price levels	PFS	Objective to minimize operational costs
Riboldi and Nord (2017)	2	Sensitivity analysis with CO_2 emission factor and heating requirements	PFS	None
Riboldi et al. (2017)	2	Three future scenarios of policies were applied, which gave different gas and power price forecasts	PFS	NPV
Hamdan and Kinsella (2017)	1	Sensitivity analysis with power load, distance from shore, carbon tax, energy cost and oil price	PFS	LCOE
Roussanaly et al. (2019)[2]	1	None	PFS	LCOE
Chokhawala (2008)	1	None	PFS	Life-cycle OPEX
Westman et al. (2010)	0	None	PFS	None
Cowell (2014)	1	Simulation of electricity price based on mean-reverting stochastic process. Also investigates the effects of a 15% decrease and increase of oil, electricity prices and carbon tax	PFS	ROA

Table 2: Literature overview on electrification papers using power from the onshore grid

Paper	CO_2 Evaluation	Uncertainty Handling	Power Source	Cost Calculations
Santibanez-Borda et al. (2021)	2	Lower and upper bounds defined for cost of generated electricity, natural gas price, offshore cable cost, power demand of network, GHG emission from natural gas combustion and interest rate. Each were assessed by changing it within the bounds and its effect on the Pareto front noted.	Wind	Objective to minimize costs
Marvik et al. (2013)	0	None	PFS and Wind	None
Korpås et al. (2012)	1	None	Wind	OPEX saved
He et al. (2010)	1	None	Wind	None
Aardal et al. (2012)	1	Sensitivity and break-even analysis w/ fuel cost, emission cost, lifetime, interest rate and O&M cost	Wind, but also battery storage	Discounts net costs
Svendsen et al. (2011)	0	None	Wind	None
Kolstad et al. (2013)	0	None	PFS and Wind	None
He et al. (2013)	1	None	Wind and power TO shore	None
Shadman et al. (2020)	0	Two power demand scenarios	Wind	LCOE
Riboldi and Nord (2018)	1	Sensitivity analysis with total capital requirements, discount rate, CO_2 price and gas price	Wind	NPV
Oliveira-Pinto et al. (2019)	1	Sensitivity analysis with OPEX	Ocean Wave energy	LCOE and IRR

Table 3: Literature overview on electrification papers using offshore wind or other sources

Here, we highlight the most important works from tables 2 and 3 and present different perspectives taken in the literature. Specifically, we separate between works performing stability studies, evaluations of the environmental impact and works considering economical aspects of electrification projects.

Firstly, an important area is stability studies, where the technical feasibility of electrification using different power duty configurations is investigated. We find this for PFS in (Westman et al., 2010), for OW in (He et al., 2010), (Svendsen et al., 2011) and (He et al., 2013) and for combinations of PFS and OW in (Marvik et al., 2013) and (Kolstad et al., 2013). Although they display promising conclusions in terms of technical aspects, several of the works conclude that further operational and economical studies are required to accurately assess the feasibility of the proposed solutions.

Secondly, a significant element in the literature is assessing the environmental impact of electrification. While papers such as (Myklebust et al., 2017) and (Chokhawala, 2008) only focus on emission reductions from replacing offshore GT with PFS, others assess the emissions related to the increase in power demand. Cheng et al. (2017) evaluates the change in CO_2 emissions in the Northern European power network due to increased power demand, while Riboldi and Nord (2017) examine the change in emissions resulting from changes in the power composition mix by using a CO_2 emission factor. This factor is calculated using a marginal approach, where the marginal increase in CO_2 from the required mix is divided by the marginal increase in power demanded. It is shown that emissions may increase when PFS is used in times when the production mix must rely on fossil fueled power plants to meet the demand. This emission factor is expanded on in (Riboldi et al., 2019) by presenting results using both a marginal and an average approach. Neither approach is deemed superior, but presenting both is useful to illustrate the effect the chosen evaluation method will have on the results. The above-mentioned papers all consider electrification using PFS, while for OW the general approach is to only report emission reductions from removing GT. An exception is found in (Santibanez-Borda et al., 2021), where emissions related to the production of wind turbines are included.

Thirdly, we observe that the economical evaluation often relies on traditional project valuation methods. NPV calculations based on deterministic forecasts are found in (Riboldi et al., 2017), while (Oliveira-Pinto et al., 2019), (Shadman et al., 2020) (Roussanaly et al., 2019) and (Hamdan and Kinsella, 2017) report findings as a levelized cost of electricity (LCOE), but where the calculations are based on the same principles as for traditional NPV calculations. A distinct exception is the ROA applied by (Cowell, 2014), where the optimal investment conditions for electrification of Edvard Grieg, a platform at the Utsira height, is investigated. The wholesale electricity price is the main stochastic element and is described using mean-reverting Ornstein Uhlenbeck process. The threshold for investment is solved by dynamic programming and Monte Carlo simulations are used for the electricity price. The work considers connecting the platform to already installed infrastructure at the Johan Sverdrup field. Thus, although the investment cost is large, a significant portion of the required infrastructure is already in place. To the author's knowledge, this is the only previous example of a ROA being applied to electrification of offshore O&G platforms.

Finally, taking on one perspective does not exclude another, and there are also multi-objective papers that consider both environmental and economical aspects. (Riboldi et al., 2019) provide an integrated assessment of environmental and economical impact of electrification using PFS. They present a power system model that accounts for the increase in power demand by simulating an optimal socioeconomic production mix based on NPV principles, which forms the basis for CO_2 calculations. (Santibanez-Borda et al., 2021) applies a multi-objective mixed-integer linear programming (MOMILP) model that simultaneously minimises GHG emissions and associated costs from an offshore platform network. The model allows for shared power generation between platforms and integration with an OWF.

3.5 Positioning this Paper

Now that we have differentiated between perspectives and categorized the existing literature, we aim to accurately position this Master's thesis in this body of literature. This paper is therefore assessed according to the formulated differentiation criteria in the previous subsection.

In this work, the problem is viewed from an economical perspective. Although we aim to represent the offshore power requirements as accurately as possible, little regard is given to providing the most thermal efficient process or whether the considered power duties will cause instabilities in the system. Furthermore, emission reductions from replacing the existing power supply is quantified, but not with an objective to evaluate the problem from an environmental perspective. The quantification of emissions is a means to establish related cost savings, and it is acknowledged that there may be emissions from both the production of electricity and in the manufacturing of wind turbines. In this regard, this paper is on level 1 in the CO_2 evaluation category.

Furthermore, our setup of NPV calculations with DCF is to a large extent similar to the approaches taken in (Riboldi et al., 2017) and (Riboldi et al., 2019). However, the inclusion of elements from RO theory with an uncertain electricity price process and dynamic programming means there are also similarities with (Cowell, 2014). There are however important points of differentiation between the latter and this thesis. The first being that we also include an option to electrify using OW and the possibility of exporting power beyond the field's lifetime. Secondly, whereas they consider an expansion option from previously installed infrastructure, our setup has no such previous instalments, which changes the dynamics of the investment costs.

As tables 2 and 3 shows, the effect of uncertain futures are often investigated through scenario analysis of price levels or by performing sensitivity analysis to observe the effect of uncertainty. To a large extent, this thesis follows this approach, but aims to differentiate itself by allowing for stochastic handling of electricity price.

Finally, to summarize the positioning in this subsection, we have assessed this thesis according to the same differentiation criteria used in the previous subsection. The result can be seen in table 4.

CO_2 evaluation	**Uncertainty handling**	**Power source**	**Cost Calculations**
Level 1	Applies four scenarios to investigate the effect of different futures of the CO_2 price. Sensitivity analysis is done by varying the price volatility of electricity and investment costs. Allows for uncertainty in the electricity price.	PFS and OW	Objective to maximize NPV. Cost calculations based on DCF. RO theory is applied by modelling electricity price as GBM, applying the SDDiP algorithm and handling path-dependencies between options.

Table 4: Positioning this paper according to the differentiation criteria established in table 1

3.6 Research Contribution and Literature Gaps

To conclude this chapter, we discuss this thesis' potential for research contributions and present identified gaps in the literature. Although we provide a research contribution by recommending a decision for an operator of the considered O&G field, this subsection will focus on contributions to the literature. Previously, we identified a lack of works applying a ROA to evaluate investments in electrification. A single work was identified, for an expansion option of already installed infrastructure, where the optimal investment timing was found under electricity price uncertainty. To the author's knowledge, this is the only application of RO to evaluate electrification of offshore platforms. Furthermore, no works taking such an approach to electrification using power from OW were found, and we therefore aim to reduce this gap through the methodology applied in this paper. Given previous applications of RO to emission reducing investments, we consider the tools required to assess electrification in this setting to be available. In addition to our formulated research questions, we therefore present another objective of this thesis. Specifically, we aim to establish the potential added value of applying a ROA to electrification investments, as opposed to traditional valuation methods. The research contribution with regards to this objective is twofold. Firstly, the results of this study shows an additional value when applying our model compared to a deterministic approach. Secondly, we have attempted to provide an overall evaluation of the benefits of applying a ROA to electrification investments.

Our applied method provides a higher expected NPV value than for the deterministic case. We associate this additional value with the potential for exporting power in the face of high electricity prices beyond the O&G field's lifetime. However, we also find that the investment timing is less subject to increased uncertainty in the electricity price and that the overall investment decision is more sensitive to changes in the investment cost of OW and carbon prices. We therefore view the inclusion of political uncertainty to handle changes in carbon prices and technical uncertainty to model the investment costs of floating OWF as possible approaches to enhance the benefits of applying RO theory to investments in electrification. Our second contribution is therefore a suggestion of further research to incorporate the effects of these elements.

Finally, we also identify a possible area of improvement in previous handling of the carbon price. The literature review on electrification found that both Cheng et al. (2017) and Riboldi et al. (2019) considers the effect of different policy scenarios on CO_2 price levels. Both base their values on scenarios established in (IEA, 2016). Converted to NOK/TC,[3] we have the following price levels for the scenarios in the EU ETS.

Scenario/**Year**	**2020**	**2030**	**2040**
Current Policies	160 NOK/TC	260 NOK/TC	347 NOK/TC
New Policies	173 NOK/TC	321 NOK/TC	433 NOK/TC
450	173 NOK/TC	866 NOK/TC	1213 NOK/TC

Table 5: CO_2 price levels in NOK/TC from 2020-2040 based on estimates from (IEA, 2016)

Given recent developments with the signaling of considerably higher carbon charges, the values in table 5 may be viewed as conservative estimates. As such, this may affect the findings in previous works. We therefore view applying updated price scenarios as a way of enhancing the relevance of previous literature.

In this section, we have differentiated between traditional project valuation methods and taking a ROA to evaluate investment opportunities. We presented several advantages of applying RO to evaluate emission reducing investments, but found limited applications on electrification problems. In the next section, we will present the problem description, where we provide a general framework that will aid in contributing to the existing body of literature on electrification.

[3]Given as Dollars per ton CO_2 in (IEA, 2016) We use conversion rate 1USD = 8,66NOK as per 22/09/2021

4 Problem Description

In this section, we describe the problem of investing in electrification of offshore O&G installations. We allow for options to electrify platforms using electricity from the onshore grid, offshore wind farms or a combination. The main objective is to answer the question: Should an investment into electrification of platforms be made, and which market conditions are required to make such an investment profitable?

We consider active offshore O&G installations that are currently being powered by on-site GT. This may be a single platform or an area solution for several installations in close proximity. The technical and operational difficulties of electrifying such installations are reflected in large investment costs. On the NCS, PFS has been implemented since 1996, while floating OWF powering platforms are in the early stages of implementation. For the latter, there may therefore be significant uncertainties in both costs and operational challenges. Furthermore, the finite nature of O&G reservoirs, and therefore lifetime of the fields, make it interesting if enough income can be generated to cover the investment cost. On the other hand, rapidly increasing CO_2 charges may lead to an escalation in operational expenditures, unless emission reducing measures are taken. In addition, market uncertainties affecting the electricity price may also have an impact on the profitability.

In this Master's thesis, we therefore target the problem of making investment decisions on electrification projects of offshore installations. We also include the possibility of using electrification infrastructure to export power to shore in a long term perspective. Although the overall motivation behind electrification is to reduce emissions, we view the problem from a business economic perspective, where we want to make the most profitable investment. Faced with such investment options, the objective is to maximize the expected NPV of the projects. This is accomplished by choosing the optimal strategic decisions over the considered lifetime. The options available to the decision makers are listed below.

- Invest in importing PFS to power offshore installations
- Invest in an OWF to power offshore installations
- Invest in exporting power to shore from an OWF

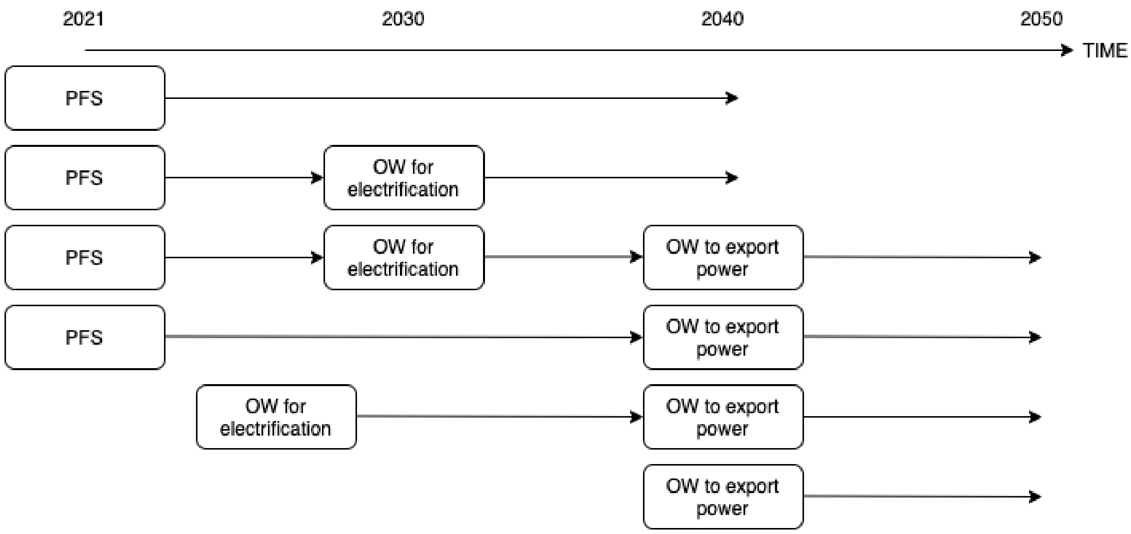


Figure 6: Combinations of the available options

The possible combinations of these options are illustrated in figure 6. They are not restricted by each other, but the related costs of each option may depend on whether or not previous investments have been made. The assigned years in figure 6 serve an illustrative purpose, but indicate the differences in the option's lifetime. Both electrification options will expire when the considered O&G fields reach their expected lifetime. Although this lifetime is subject to uncertainties from technological developments, new field discoveries and political involvement, it is treated deterministically and assumed to be given by operators. The latter option involving export of produced power to shore does not have such an expiry date and will stay alive until the end of the considered time period. The inclusion of this option is to capture potential additional value in a long-term perspective when necessary infrastructure might be in place. Therefore, it should not be viewed as a choice between electrification or export, as the export option is restricted as long as there remains hydrocarbon production at the field. The options can be activated once a year and we are using annual price levels for electricity, natural gas, NOx and CO_2 over the entire time period. Each strategic decision will affect the discounted NPV calculations, which is composed of revenues, OPEX and CAPEX.

Revenues

When replacing the power supply from GT, an additional freed gas becomes available for export. Here, we assume that the additional gas can be exported using existing infrastructure and that the gas is demanded in the market. We clarify that we do not consider the total revenue generated from the sale of hydrocarbons, but only from the amount not combusted in GT due to electrification. This is in line with traditional NPV decision criteria, where only the elements relevant to the decisions in question are considered. Additionally, revenue can be generated from the sale of exported power to shore from OW, which will depend on the price level of electricity.

OPEX

Although not considered as a part of the revenues, a main motivation for electrification projects is the potential cost reductions by emitting less GHG. In this paper, we consider reductions in CO_2 and NOx emissions. These are calculated from the annual emissions savings associated with replacing GT power supply, multiplied with the CO_2 charge and NOx cost at that time. Due to operational changes when electrifying, activating options may also lead to changes in operational costs that must be considered. These are case specific and are therefore assumed to be given by the operators. Finally, the cost of the supplied electricity from shore is considered, where the annual offshore power demand is multiplied with price levels for electricity.

CAPEX

Each option will have a corresponding investment cost, which is seen as the strike price to activate the option. These are assumed to be payed in full when the option is taken and the effect on cash flows is assumed to be immediate. Given that electrification using PFS has been done since 1996, we view the technological solutions as mature and therefore assume a constant investment cost until the field's lifetime. This is not necessarily the case for the strike price for OW options. With an expectancy for learning effects and technological development, this is expected to decrease. Such a learning rate can be directly applied to the investment cost or included in cost estimates from relevant literature. Finally, previously activated options may affect the strike prices due to the possibilities of reusing installed infrastructure.

Price Uncertainty

As was presented in section 2.3, there are inherent uncertainties in prices of natural gas, electricity and CO_2. Our framework allows for all these prices to be handled stochastically. In this thesis, however, we acknowledge the uncertainties in natural gas and CO_2 prices, but apply deterministic forecasts available from reports in the literature. The effect of this handling is investigated through analysis of different future scenarios. We do allow for uncertainty in the electricity price, where we apply Monte Carlo simulation to a chosen stochastic process for this price. A more detailed overview of the handling of the electricity price is given in section 6.

In this section, we have presented available decisions and described the considered problem of this Master's thesis. In the following section, we will formulate the optimization model mathematically and provide more details on the components in the NPV function.

5 Mathematical Model

In this section, we present the mathematical formulation of a multistage stochastic integer programming (MSIP) model used to solve the problem described in the previous section. We start by giving assumptions in the model framework and provide an overview of the sets, indices and parameters used. With an objective of maximizing the expected NPV of a project, we present the decision variables available and how they will affect each element in the NPV function. The final subsection considers the constraints for activating each option, as well as restrictions related to the inter-dependencies between these.

5.1 Modelling assumptions

Here, we provide assumptions used in the model framework.

- All costs and revenue elements are given in units of [NOK]
- Amounts of power, natural gas and emissions are given as annual sums
- Price levels are given as annual prices
- The investment cost of each option is paid in full when the option is taken and the resulting effect on cash flows starts immediately
- Electricity prices are given as [NOK/MWh], and yearly power consumption given in [MW]. The yearly amounts of power supplied from shore and/or produced by wind turbines are therefore multiplied with hours in a year to get units of [MWh]

5.2 Sets, Indices and Parameters

Let $\mathcal{T} = \{0, ..., T\}$ be the set of time periods, indexed by t. Each period lasts one year and T represents the last year we consider the problem. With these time steps, we allow for annual decisions. In table 6, we present a description of all the parameters used in the model formulation.

Parameter	**Description**
P_t^{GAS}	Price of natural gas at time t
P_t^{EL}	Price of wholesale electricity at time t [NOK/MWh]
$C_t^{CO_2}$	Cost of emitted CO_2 at time t [NOK/ton CO_2]
C_t^{NOx}	Cost of emitted NOx at time t [NOK/kg NOx]
G_t^{PFS}	Amount of freed natural gas related to electrification using PFS at time t [Sm^3]
G_t^{OW}	Amount of freed natural gas related to electrification using OW at time t [Sm^3]
Q_t^{PFS}	Amount of imported electricity from shore at time t
Q_t^{EXP}	Amount of exported electricity to shore at time t
$E_t^{CO_2,PFS}$	Amount of CO_2 saved if PFS is supplied at time t
$E_t^{CO_2,OW}$	Amount of CO_2 saved due to OW electrification at time t
$E_t^{NOx,PFS}$	Amount of NOx saved if PFS is supplied at time t
$E_t^{NOx,OW}$	Amount of NOx saved due to OW electrification at time t
O_t^{PFS}	Change in operational costs for PFS option at time t
O_t^{OW}	Change in operational costs for OW electrification option at time t

Parameter	Description
O_t^{EXP}	Change in operational costs for OW export option at time t
$\underline{T}^{PFS}$, $\underline{T}^{OW}$, $\underline{T}^{EXP}$	Lower bounds for the time each option is available
$\bar{T}^{PFS}$, $\bar{T}^{OW}$, $\bar{T}^{EXP}$	Upper bounds for the time each option is available
K_t^{EXP}	Investment cost of export option given no previous investments
$K_t^{EXP\|PFS}$	Investment cost of export option, given previous PFS investment
$K_t^{EXP\|OW}$	Investment cost of export option, given previous OW investment
$K_t^{EXP\|PFS \wedge OW}$	Investment cost of export option, given previous PFS and OW investment
$K_t^{OW\|PFS}$	Reduction of investment cost of OW-electrification, given previous PFS investment
α	Transmission loss from transferring power to/from shore [%]
τ^p	Tax rate used for income from sale of hydrocarbons
τ^c	Corporate tax rate used for income from sale of electricity
r	Discount rate
ρ_t	Discount factor at time t

Table 6: Description of parameters used in the model

5.3 Decision Variables

In this model, we have two categories of decision variables. The first are binary variables representing the three available options, but we also introduce a set of continuous variables to account for the dependencies between these options. The binary decision variables takes the value 1 if an option is taken at time t and 0 if not. These are given as

z_t^{PFS}	Binary decision variable for option to electrify using PFS
z_t^{OW}	Binary decision variable for option to electrify using OW
z_t^{EXP}	Binary decision variable for option to export power from OW

These have two important functions in the model. They are state variables, providing information on which decisions have previously been made, but also serve to activate costs related to each option. As a result, once an option is activated, the binary variable will keep the value 1 in all future time periods. In addition, both strike prices and future cash flows may depend on the interdependency between these options. To include this effect, we define a series of local continuous variables, whose values can be derived from the information from the three binary z_t-variables. These take the value 1 if the option is taken, given previous investments have been made as described below, and 0 if not. We first describe the variables considering exporting power to shore, where the value of each will affect the strike price of the export option.

x_t^{EXP}	Power export without previous OW or PFS investments
$x_t^{EXP\|PFS}$	Power export when PFS option has previously been taken on
$x_t^{EXP\|OW}$	Power export when OW electrification option has previously been taken on
$x_t^{EXP\|PFS \wedge OW}$	Power export when both PFS and OW electrification options have previously been made

We clarify that while the binary z_t-variables remains 1 for every period until T after being activated, these continuous x_t-variables will only take the value 1 at the time of investment and 0 in the remaining time periods. Next, we have variables for investing in OW-electrification, given that we have previously invested in PFS. Two variables are defined for this case, as we account for impact on both annual cash flows and the strike price. Thus, we have

$x_t^{OW\|PFS,INV}$	OW for electrification when PFS has been done, affecting the strike price
$x_t^{OW\|PFS}$	OW for electrification when PFS has been done, affecting the annual cash flow

The first variable, $x_t^{OW|PFS,INV}$, has the same properties as the continuous variable listed above, where it takes the value 1 at time of investment and 0 in all other periods. Given that the latter variable, $x_t^{OW|PFS}$, accounts for cash flows in every period, its value will remain 1 in the remaining periods if activated. In the next subsection, we present the objective function and its components. This will be represented through the local variables described in table 7.

Variable	**Description**
NPV_t	Net Present Value at time t
REV_t	Yearly revenue at time t
$OPEX_t$	Operational expenditures at time t with PFS
$CAPEX_t$	Capital expenditures at time t
I_t^{PFS}	Investment cost of PFS option at time t
I_t^{OW}	Investment cost of OW option to electrify at time t
I_t^{EXP}	Investment cost of OW to export power to shore at time t

Table 7: Variables used to represent objective function in the model

5.4 Objective Function

With an objective to maximize the expected NPV of our investment opportunities we have the following objective function.

$$\max \mathbb{E}\left[\sum^{T} NPV_t\right], \tag{1}$$

where

$$NPV_t = \rho_t(REV_t + OPEX_t - CAPEX_t) \qquad t \in T \tag{2}$$

Here, REV_t is the revenue at time t, $OPEX_t$[4] are the changes in operational expenditures due to decisions taken at time t, $CAPEX_t$ the capital expenditures at time t and ρ_t is the discount factor at time t, given as

$$\rho_t = \frac{1}{(1+r)^t}, \tag{3}$$

where r is the discount rate.

5.4.1 Revenues

This model considers two sources of revenue: additional freed gas from electrification measures and income generated through export of power generated from OW. The revenues at time t are

[4]The OPEX term is added here as a result of its formulation in section 5.4.2

therefore expressed as

$$REV_t = (1-\tau^p)P_t^{GAS}[G_t^{PFS}z_t^{PFS} + G_t^{OW}z_t^{OW}] + (1-\tau^c)(1-\alpha)P_t^{EL}Q_t^{EXP}z_t^{EXP} \tag{4}$$

The first term represents the freed gas, where τ^p is the tax rate applied to the sale of O&G, P_t^{GAS} the price of natural gas at time t and G_t^{PFS} and G_t^{OW} the freed amounts of natural gas from each electrification option at time t.

The second term shows the revenues from the sale of exported power, where τ^c is the corporate tax rate, α is the transmission loss in the power cables, P_t^{EL} the electricity price at time t and Q_t^{EXP} the annual amount of power exported at time t.

5.4.2 Operational Expenditures

Furthermore, changes in operational expenditures occur from CO_2 and NOx charges saved, cost of supplied electricity and changes in operational costs for each option[5]. The variable for OPEX at time t is therefore given as

$$\begin{aligned} OPEX_t = [C_t^{CO_2}E_t^{CO_2,PFS} + C_t^{NOx}E_t^{NOx,PFS} - O_t^{PFS} - \frac{1}{1-\alpha}P_t^{EL}Q_t^{PFS}]z_t^{PFS} \\ + \quad [C_t^{CO_2}E_t^{CO_2,OW} + C_t^{NOx}E_t^{NOx,OW} - O_t^{OW}]z_t^{OW} \\ - \quad O_t^{EXP}z_t^{EXP}, \end{aligned} \tag{5}$$

where the first term considers the costs for PFS, the second for OW and the third is the export option. The description of the following parameters was given in table 6, but are repeated here. $C_t^{CO_2}$ and C_t^{NOx} are the CO_2 and NOx charges at time t, $E_t^{CO_2,PFS}$ and $E_t^{NOx,PFS}$ the amounts of saved CO_2 and NOx emissions for PFS option and $E_t^{CO_2,OW}$ and $E_t^{NOx,OW}$ the same for OW electrification option at time t. In addition, Q_t^{PFS} is the amount of imported PFS at time t and O_t^{PFS}, O_t^{OW}, O_t^{EXP} the changes in operational costs for each option.

5.4.3 Capital Expenditures

The capital expenditures consists of the investment cost for the different options at time t. We start with the investment cost of the option for exporting power, I_t^{EXP}, at time t. Each continuous variable for the export option will have a different strike price K_t, depending on previous decisions. The total expression for the export option then becomes

$$\begin{aligned} I_t^{EXP} = K_t^{EXP}x_t^{EXP} + K_t^{EXP|PFS}x_t^{EXP|PFS} + K_t^{EXP|OW}x_t^{EXP|OW} \\ + K_t^{EXP|PFS\wedge OW}x_t^{EXP|PFS\wedge OW}, \end{aligned} \tag{6}$$

where K_t^{EXP}, $K_t^{EXP|PFS}$, $K_t^{EXP|OW}$ and $K_t^{EXP|PFS\wedge OW}$ are the respective investment costs at time t for power export given no, PFS, OW or both options taken previously. Only one of these may be activated.

The total for all options can then be expressed as

$$CAPEX_t = I_t^{PFS}(z_t^{PFS} - z_{t-1}^{PFS}) + I_t^{OW}(z_t^{OW} - z_{t-1}^{OW}) - K_t^{OW|PFS}x_t^{OW|PFS} + I_t^{EXP}, \tag{7}$$

[5] In the context of this paper, operational expenditures is used as a broader term, which includes both operational costs and other cash flows.

where I_t^{PFS}, I_t^{OW}, I_t^{EXP} represents the investment costs for each option at time t. The differences in binary variables from t to $t-1$ is to ensure that the investment cost only happens once for each option. In addition, $K_t^{OW|PFS}$ is the reduction in the investment cost for OW-electrification if PFS has been done previously.

5.5 Constraints

This subsection will show the constraints applied in the model. We start by presenting the restrictions for the three binary variables, before showing the relationships that dictates the inter-dependencies between options.

We start with the binary restrictions for the three main decision variables.

$$z_t^{PFS} \quad \in \{0,1\}, \qquad t \in [\underline{\mathrm{T}}^{PFS}, \bar{T}^{PFS}] \tag{8}$$

$$z_t^{OW} \quad \in \{0,1\}, \qquad t \in [\underline{\mathrm{T}}^{OW}, \bar{T}^{OW}] \tag{9}$$

$$z_t^{EXP} \quad \in \{0,1\}, \qquad t \in [\underline{\mathrm{T}}^{EXP}, \bar{T}^{EXP}], \tag{10}$$

where $\underline{\mathrm{T}}$ is the first time period the option is available and $\bar{T}$ the last.

If an investment has been made, it is irreversible and this characteristic is ensured by

$$z_{t+1}^{PFS} \geq z_t^{PFS}, \quad z_{t+1}^{OW} \geq z_t^{OW}, \quad z_{t+1}^{EXP} \geq z_t^{EXP} \qquad t \in T \tag{11}$$

Inter-dependency constraints

We have a continuous variable for each combination of previous options, which are expressed through the values of the three binary decision variables. We therefore establish equivalence terms to represent these relationships. We will present this for each combination of options.

Export power if no previous decision has been made

$$\{x_t^{EXP} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 0\}, \qquad t \in T \tag{12}$$

where we include both t and $t-1$ terms to ensure that the investment cost only happens once. Ensuring this relationship through constraints are accomplished by turning equivalences into opposite implications and formulating restrictions for each implication. As this is an extensive process, the procedure and restrictions for each inter-dependency can be found in appendix D.

Export power if OW electrification investment has been done previously

$$\{x_t^{EXP|OW} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 0\} \qquad t \in T \tag{13}$$

Export power if PFS investment has been done previously

$$\{x_t^{EXP|PFS} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \qquad t \in T \tag{14}$$

Export power after both OW and PFS has been done

$$\{x_t^{EXP|PFS\wedge OW} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \qquad t \in T \quad (15)$$

Invest in OW given PFS has been done previously

As mentioned previously, we have one variable for the investment cost and one for the annual cash flows when investing in OW-electrification, given PFS. The difference between their formulations is that the variable used for the investment cost requires that the option was not exercised in the previous time period. This is to ensure that the cost only happens once. When accounting for the investment cost, we have

$$\{x_t^{OW|PFS,INV} = 1\} \iff \{z_t^{OW} = 1\} \wedge \{z_{t-1}^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\}, \qquad (16)$$

whilst the cash flow term is handled by the following constraint.

$$\{x_t^{OW|PFS} = 1\} \iff \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \qquad (17)$$

Finally, each of the local continuous variables are restricted to take values between 0 and 1. This is ensured by

$$x_t^{EXP}, x_t^{EXP|PFS}, x_t^{EXP|OW}, x_t^{EXP|PFS\wedge OW}, x_t^{OW|PFS}, x_t^{OW|PFS,INV} \in [0,1] \qquad t \in T \qquad (18)$$

In this section, we have provided the mathematical formulation of an MSIP problem that will take inputs from a case study of an offshore platform. We have presented the available decision variables and shown how their inter-dependencies are accounted for. In addition, we have given the building blocks of the objective function and presented constraints. This model framework allows for both stochastic and deterministic price inputs. Before proceeding with our presentation of the case study, we provide a section on the handling of uncertainty in the electricity price and the method used for solving the formulated model.

6 Handling of the Electricity Price

In the previous section, we presented a model framework that allows for both deterministic and stochastic price inputs. In this section, we will present how the main stochastic element of the modelling, the electricity price, is handled. First, we must apply an appropriate stochastic process to represent this price. In the literature, there are particularly two prominent processes used for electricity prices: the Geometric Brownian motion (GBM) and the mean-reverting Ornstein-Uhlenbeck (OU) process. For each, we present theoretical background from (Dixit and Pindyck, 1994), before the merits of the processes are discussed and we provide our reasoning for assuming the price follows a GBM. Finally, we introduce the SDDiP algorithm used for solving the formulated MSIP problem.

6.1 Theoretical Background

We first present aspects of a Wiener process, which is a continuous-time stochastic process with three important properties.

- It is a Markov process, which means that the probability distribution for all future values of the process only depends on the current values, and is unaffected by past values of the process or any other current information.
- It has independent increments, meaning the probability distribution for the change in the process is independent of any other time interval.
- Changes over any finite interval of time are normally distributed, with a variance that increases linearly with the time interval.

These properties are relevant as the Wiener process serve as a building block for both the GBM and OU processes. First, we have a general expression for the change of a stochastic process x.

$$dx = a(x,t)dt + b(x,t)dz \tag{19}$$

where $a(x,t)$ is the drift coefficient and $b(x,t)$ the variance coefficient or diffusion term that are both functions of the current state and time. Furthermore, dx is the change in the stochastic process, dt the change in time and dz is the increment of a Wiener process.

Ornstein-Uhlenbeck

With the framework established, we present the mean-reverting OU process. As the name suggests, it has a tendency to revert towards a mean level, and is considered appropriate for when price levels tend to respond to fluctuations by returning back to a mean level. It can be expressed as

$$dx = \eta(\overline{x} - x)dt + \sigma dz, \tag{20}$$

where η is the speed of reversion, $\overline{x}$ the level which x tend to revert to and σ the standard deviation.

Geometric Brownian motion

On the other hand, the GBM is given as

$$dx = \alpha x dt + \sigma x dz, \tag{21}$$

where α is a constant drift parameter.

Dixit and Pindyck (1994) claim that mean reverting processes are useful for raw commodities such as copper or oil because the cost of production might be related to long term marginal costs, while the properties of a GBM is often fitting for more speculative asset prices. An analysis of the Nordic power exchange by Lucia and Schwartz (2002) showed that the volatility of the electricity price is consistently different for warm and cold seasons. As such, this property could be captured by mean-reverting distributions. Keppo and Lu (2003) argues that despite seasonal fluctuations, the electricity price forward curves may be accurately represented by a GBM. They argue that the expected cycles are captured in the forward curves, resulting in more stable processes. Finally, Fleten and Maribu (2004) discusses which choice is most appropriate for capturing the long-term dynamics of the electricity price. It is concluded that although a GBM may ignore short term mean reversion, long term investments such as wind mills are likely to be less affected by such reversions. We acknowledge that both processes may be applied, but given that we are regarding the problem of electrification over the next 20 years and power export over the next 30 years, we have a long-term perspective. We therefore apply a GBM to represent the electricity price.

6.2 Electricity Price as a Geometric Brownian Motion

Here, we expand on equation 21 to provide the expression we apply for the electricity price in the modelling.

$$dP_t^{EL} = \alpha P_t^{EL} dt + \sigma P_t^{EL} dz, \tag{22}$$

where

- P_t^{EL} is the electricity price at time t
- dP_t^{EL} the change in electricity price
- dt is the change in time
- dz is the increment of a Wiener process and

  $$dz = \epsilon_t \sqrt{dt}, \quad \epsilon_t \sim N(0,1), \tag{23}$$

  where ϵ_t is a normally distributed random variable with a mean of zero and standard deviation of 1.
- α is the annual growth rate
- σ is the annual volatility

Based on the listed properties of a Wiener process and through application of Itô's Lemma, it can be found that when the electricity price follows the GBM in equation 22, then the change in the expression $F(P_t^{EL}) = log(P_t^{EL})$ is given as

$$dF(P_t^{EL}) = (\alpha - \frac{1}{2}\sigma^2)dt + \sigma dz, \tag{24}$$

where every annual time interval the change in the logarithm of the electricity price is normally distributed with a mean of $(\alpha - \frac{1}{2}\sigma^2)$ and variance σ^2. From the properties of the log-normal distribution we then implement the electricity price according to equation 25, where we have applied annual time steps.

$$P_t^{EL} = P_{t-1}^{EL} e^{(\alpha - \frac{1}{2}\sigma^2) + \sigma\epsilon_t} \tag{25}$$

Our next step then becomes to find appropriate values for the drift and diffusion terms for the simulations. These can be found using forward curves or implied volatility, but we base ourselves on historical day-ahead prices traded on the Nord Pool exchange (Nord Pool, 2021). Here, we are also able to differentiate between regions in Norway and apply the market data from the region in closest proximity to the considered case study. Using data from 2013-2020, we calculate the annual average of the daily price levels. We apply the logarithmic return for α and the standard deviation of log-returns for σ. Furthermore, we obtain the initial value of the electricity price, P_0^{EL}, from the average value in 2021[6].

The resulting values are

$$P_0^{EL} = 417 \text{ NOK/MWh},$$

$$\alpha = 0{,}037,$$

$$\sigma = 0{,}29.$$

6.3 Stochastic Dual Dynamic Integer Programming

Before presenting the real life case study, we briefly introduce the approach taken to solve the MSIP problem and the handling of the specified uncertain process. The MSIP is solved using the Stochastic Dual Dynamic integer Programming (SDDiP) algorithm presented in (Zou et al., 2019). The inspiration behind this approach is based on (Bakker et al., 2021), where the same algorithm is used to solve a RO problem for investments in developing mature offshore oil fields.

The SDDiP algorithm is based on principles of dynamic programming (Bellman and Dreyfus, 2015), using an expected cost-to-go function for each time stage. Given a state, as defined by the binary state variables, and an approximated cost-to-go function, the optimization model provides a decision for each stage. Each state of the model is therefore mapped to a decision, which we refer to as a policy. Based on the solutions of the optimization model for each stage, the SDDiP algorithm iteratively tries to improve the approximated cost-to-go functions using a *forward pass* and *backward pass*. For the former, the current policy is evaluated on a set of sampled scenarios, thus providing a set of policy values. For the latter, the algorithm works backwards from the last stage, using solutions of future stages to improve the estimated cost-to-go function. Finally, this procedure is repeated until we meet a specified convergence criterion and we have obtained a policy.

With the principles of the SDDiP algorithm established, we can describe the steps taken to obtain the policies, and by extension estimated optimal decisions. First, we create what is referred to as the true problem, where we specify the constraints, variables and objective function as seen in section 5. Here, we also specify the electricity price process as a GBM with the drift and diffusion parameters listed above. This establishes the true problem as a continuous Markovian problem, which must be discretized before it can be solved. The continuous true distribution is then represented by means of a discrete Markov chain, where we have to specify the number of Markov states per time period. Next, the discretized problem is solved, thus providing a feasible and implementable policy. Finally, this is evaluated back on the true problem, which provides an estimate for the expected NPV and optimal choice of options.

In this section, we have provided insight on how we handle the stochastic nature of the electricity price in this thesis. We assume the uncertain process can be represented as a GBM and obtain estimates for the drift and diffusion parameters based on historical data. Finally, we have introduced the SDDiP algorithm and how it has been applied for our problem. In the next section, we present the offshore field where our model has been applied, before the results of the computational study are given in the following section.

[6] The annual average from 2021 is calculated from 01/01/2021 until 09/10/2021.

7 Case Study

The case for this study is a real life offshore installation in the Norwegian Sea, provided by an operator at this O&G field. The installation in question is a gas processing facility, where the operator is currently considering electrification measures. Natural gas is processed at the installation, before being transported to shore, where it is treated further and exported to the European market. First, we introduce the offshore installation and its power producing processes. Second, relevant costs are presented, which is followed by price data used in the modelling. All the information and data presented throughout this section forms what we will refer to as the base case.

7.1 Facts on the Offshore Installation

We start by presenting general information on the offshore site and installation, which can be seen in table 8. This subsection will then expand on the gas demand and offshore power producing processes.

Location	Norwegian Sea
Sea depth at site	240-320m
Distance from shore	200km
Annual power demand	80-100MW
Expected lifetime	2040
Daily amount of exported natural gas	27 million Sm^3/day

Table 8: Information on case study

7.1.1 Exported Gas

The field has an expected lifetime until 2040. Thus, it will keep exporting natural gas until this point. As of 2021, the daily amount of exported gas is 27 million Sm^3/day [Standard cubic meters/day]. This will be reduced towards 2040, and is estimated to decrease 6-8% per year from 2028. The development over the estimated lifetime using a 7% decrease is seen in figure 7. The monetary value of this exported gas is not included in the calculations as this income is the same for all options, but it is of importance as less export will result in a gradual decrease in the power demand at the platform. If an electrification option is activated, there will be more gas available for export. It is estimated that 3% of the extracted natural gas is being used to fuel the GT at the field, which corresponds to a total of 0,85 million Sm^3/day. We assume that the infrastructure in place can handle the increased amount of natural gas.

7.1.2 Gas Turbines

Here, we provide insight into the situation for the offshore GT. At the platform, the total power demand is supplied by five GT, which supply between 18-25MW annually and have different areas of use. The situation for each is described in this paragraph and an overview is provided in table 9. Two of them cover the power needed to operate the platform. In case of electrification, these will be the first priority to be replaced. They are deemed easy to replace, as this would not require significant modifications for the platform's power distribution. The next two are supplying power needed to export the gas to shore. These are more challenging to replace as they are part of an integrated process. One is categorized as not available for replacement, which means only one is considered. However, due to the expected decrease in exported gas from the platform, and therefore lower power demand, only one GT for export is expected to be required beyond 2033. Thus, no GT for export may be replaced after this. The final GT is used to produce the power

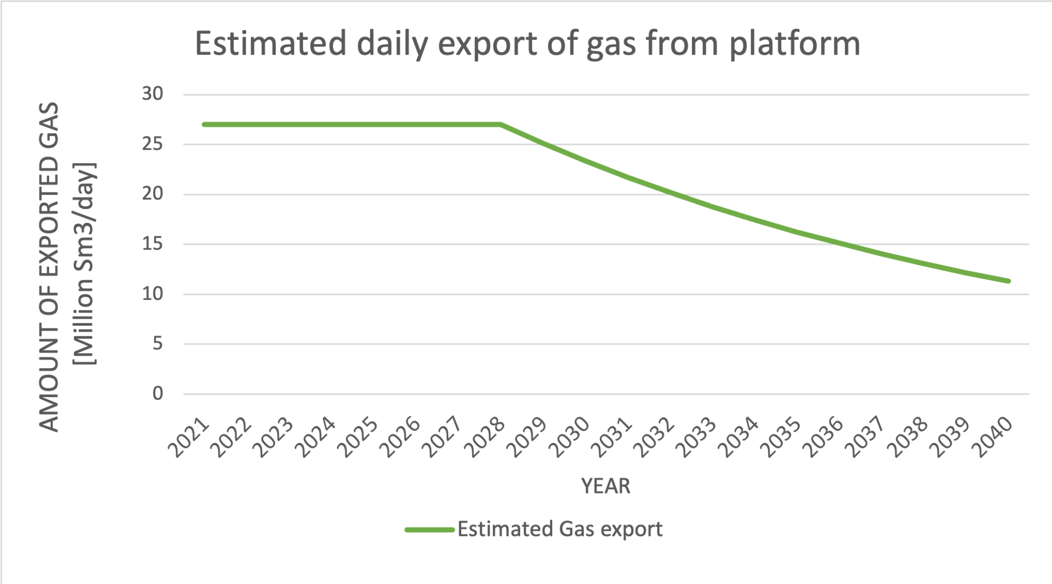


Figure 7: Daily export of natural gas from the platform over the lifetime of the field

needed to inject gas back into the reservoir as a means of enhancing oil recovery. This one is integrated with the two GT required for gas export and will deliver gas lift up until 2032/33 and be removed afterwards. It is deemed not likely to be replaced due to its integrated nature with the offshore system. In total, we have three GT whose power supply can be replaced until 2033 and two after. When electrifying, there are risks related to the supply security. As a result, the operator is planning on keeping the GT offshore as back up in case of electrification. This is not only a matter of keeping operations running, but also an HSE consideration.

Total of 5 GT	**Area of Use**	**Information**
2 GT	Power production	Both can be replaced
1 GT	Power for export of gas	Can be replaced, but expected to be removed in 2033
1 GT	Power for export of gas	Can not be replaced
1 GT	Is used to produce power for gas injection	Can not be replaced. Will be removed in 2032/2033

Table 9: Information on the gas turbines at the offshore platform

7.1.3 Power Duty

When replacing the power supply from three GT as described above, there is a potential for replacing between 54-75 MW annually. In addition, should an electrification investment be taken, the operator will also include the power duty of a subsea compressor (SSC) that is currently powered by GT from a nearby installation. This installation is set to be decommissioned in 2030, meaning this power duty must be supplied by the main platform beyond this. The SSC has an average annual power need of 24MW, with a maximum of 28MW. Therefore, the total power demand may vary between 78-103 MW. In this study, we therefore assume an annual demand of 100MW until 2033. Between 2034-2040, we consider one less GT and assume an annual demand of 75MW. Although we allow for electrification using both PFS and OW, we do not allow for replacing more than the annual power demands given here. A fixed annual level is used to simplify the calculations, but it is important to note that there will be variations in the power demand. The largest variations in power produced are found in the GT supplying power for gas injection. Given that this is not considered for removal, the potential negative effect of the simplifying assumption is less. The integrated nature of the GT, means that some will be operated at optimal conditions, while others will vary depending on the power demand at that time. By assuming the same operating conditions for each GT, we simplify calculations, but acknowledge that there may be a loss of accuracy. We apply this approach as it allows for establishing a linear expression between the replaced amounts of power and values of emission savings and freed gas.

Table 10 presents the savings in natural gas and emissions when replacing 75MW and 100MW annual power demands. These values are based on emission factors obtained from public annual reports from the field in question and information provided from the operator. A more detailed review of these numbers and the underlying calculations can be found in appendix A.

Type of data	**Value**	
	2021-2033(100MW)	**2034-2040(75MW)**
Daily fuel gas consumption in GT	0,706 mill Sm^3/day	0,538 mill Sm^3/day
Yearly fuel gas consumption in GT	257,7 mill Sm^3/year	196,4 mill Sm^3/year
CO_2 emission factor	0,00234555 ton CO_2/Sm^3	
NOx emission factor	1,8 g/Sm^3	
Annual CO_2 saved	0,604 million ton	0,461 million ton
Annual NOx saved	0,464 million kg	0,353 million kg

Table 10: Savings in natural gas and emissions by replacing the annual power supply of 75MW and 100MW

7.2 Cost Data

This subsection will provide the costs related to each option. We start by presenting the investment costs, where we emphasize that the strike price of each option will vary depending on previous investments. We also provide the annual operational costs, before summarizing the presented data in table 12.

7.2.1 Investment Costs

A point of interest in this paper is to capture the value of path-dependencies between options, where infrastructure from electrification can be utilized beyond the hydrocarbon extraction operations. To capture this in the modelling, we break the investment cost into the components shown in table 11. The onshore substation connects the system to the onshore power grid. This is then connected to an offshore control hub, which receives, controls and directs the power to where it is needed. The pathway for power cables needs to be prepared and the cost of the cables is also included. Finally, we have the cost of the wind turbines and other offshore infrastructure. An important assumption made is that for a modification cost, the same infrastructure for PFS and OW can be used to export power produced from wind to shore.

Table 11 shows the infrastructural elements that are shared between each option. As such reutilization is likely to reduce investment costs, we will present the estimated strike prices for each options individually and reductions depending on previous investments. The estimates are based on available data from the operator and relevant literature. In addition, some assumptions have been made, which therefore represent a source of uncertainty. We provide all relevant costs in this subsection, but a more through overview of these and of our assumptions is given in appendix B.

Power from Shore

Element	PFS	OW to power platform	OW for export
Onshore substation	✓		✓
Offshore control hub	✓	✓	✓
Cable pathway	✓		✓
Power cables	✓		✓
Floating Wind turbines		✓	✓

Table 11: Shared infrastructure between options

If the decision to electrify using PFS is made, the investment cost is set at 8,5 billion NOK (bNOK). This cost includes the necessary infrastructure, with approximately 60% being related to the cables. When also including the necessary changes to connect the SSC to the onshore power supply, there is an additional cost of 1,5 bNOK. In total, we have an investment cost 10 bNOK, dimensioned for a 100MW power supply. Here, it is important to note that if it is decided to not electrify, the power demanded of the SSC will have to be supplied from the main installation from 2030. The estimated cost of ensuring this supply using GT from the gas processing facility is 3,5 bNOK, which will have to be paid in 2030. Therefore, without accounting for the time value, there is a potential saving of 2 bNOK if the decision is made to electrify.

Offshore Wind for Electrification

A significant challenge of accurately estimating costs for floating OW farms is the immaturity of technology and lack of large scale projects. However, given the similarities between this case and Hywind Tampen, we base our estimates on data from public impact assessment reports (Equinor, 2019). Furthermore, to incorporate the effect of learning on these estimates, we use the slope from the graph shown in figure 3, which showed the expected learning factor for floating OW turbines (DNV GL, 2020). The yearly percentage change from this learning factor is applied to the investment cost of the Hywind Tampen case. Linearizing from the values in (Equinor, 2019), 5bNOK for 88MW, we get 5,68bNOK for 100MW capacity. The resulting development of the investment cost for our case is seen in figure 8. As table 11 shows, the shared infrastructure between the electrification options is the offshore control hub. A breakdown of the estimate of the control hub is given in appendix B, but is estimated at 15% of the PFS cost, meaning 1,275 bNOK.

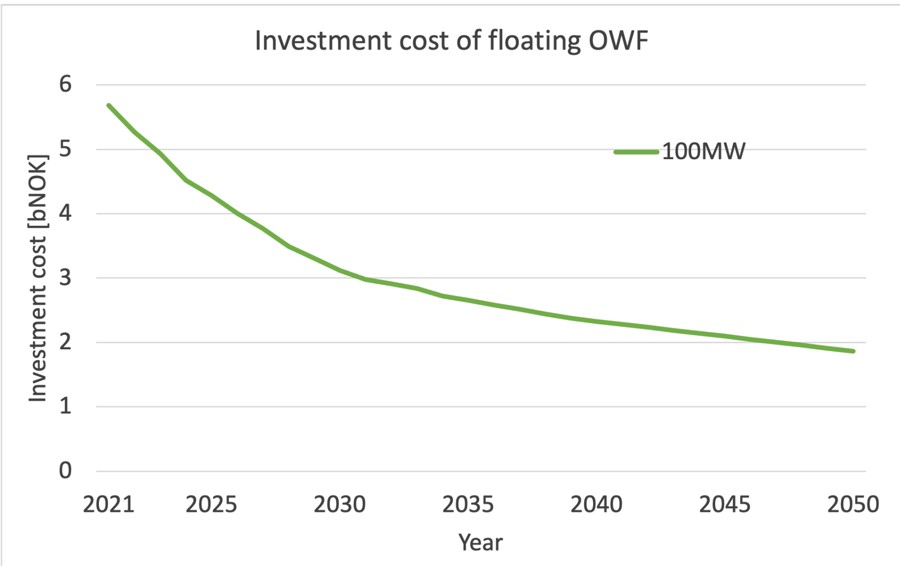


Figure 8: Investment cost of 100MW floating offshore wind farm until 2050

Offshore Wind for Export

The considered electrification options are available from 2021 until the the of the field's lifetime in 2040. Therefore, the option to export power to shore is available from 2041. Although this option is not restricted by an upper bound in real life, we only consider the problem until 2050. Although the option value of the export option may increase if we allow for more time periods, this bound is set to maintain a certain level of accuracy in estimated inputs.

We base our estimate for a 100MW wind farm exporting power on the sum of the infrastructure from PFS and OW options, net of the shared offshore power hub. In 2021, the strike for OW for export is therefore set at 12,905 bNOK[7], which is set to decrease as the OW cost is reduced. To capture the real life situation, we apply an additional modification cost for these options. For export given PFS, we must alter the offshore control hub to switch supply from the platform to the onshore grid, whilst for export given OW, we must modify the installations to allow for power to be transmitted in the opposite direction. In addition to the cost of making these changes, we are also faced with planning costs here. We acknowledge the difficulty in establishing accurate estimates for these costs, which won't occur until 2041. Initial estimates are therefore 0,5 bNOK for export given OW and 1 bNOK for export given PFS.

Type of cost	**Time considerations**	**Amount**
Cost of electrification using PFS	Option expires in 2040	8.5 bNOK
Cost of connecting SSC to supply from PFS	Not relevant after 2030	1.5 bNOK
Total investment cost of electrification using PFS	Option expires in 2040	10 bNOK before 2030 8,5 bNOK after 2030
Cost of connecting power supply of SSC to the main platform.	Cost will happen if the decision to electrify is not taken before 2030. Must be paid in 2030	3,5 bNOK
Cost of OW for electrification	Option expires in 2040	5,68 bNOK in 2021. See figure 8
Cost of OW for export	Option expires in 2050	12,905 bNOK in 2021 10,83 bNOK in 2041
Cost of OW for export, given PFS options is activated	Option expires in 2050	5,405 bNOK in 2021 3,33 bNOK in 2041
Cost of OW for export, given OW-electrification option is activated	Expires in 2050	8 bNOK
Modification cost for export given PFS	Relevant beyond 2040	1 bNOK
Modification cost for export given OW-electrification	Relevant beyond 2040	0,5 bNOK

Table 12: Relevant cost data for the decision to invest in electrification

7.2.2 Operational Costs

Here, we present the O&M costs for each options. Specifically, we consider the changes in operational costs when activating an option. These changes do not depend on previous investment and

[7]8,5 bNOK + 5,68 bNOK - 1,275 bNOK

are only activated if one of the three main options are taken. For PFS, the operator of the field estimates an expected increase of 50 million NOK (mNOK) annually. This value is held constant, and consists of the cost of operating the offshore power hub and maintenance of the GT kept as backup. For the operational costs for, OW we base ourselves on the data from (De Vita et al., 2018). Here, O&M costs for OWF are estimated until 2050 for low, medium, high and very high capacity factor. A very high capacity factor refers to remote locations and increases from 0,47 in 2020 to 0,59 in 2050. As will be shown in section 7.4, the conditions at the case site gives an average capacity factor of 0,58. We therefore base our estimates on a very high capacity factor, which can be seen in table 13[8]. With 100MW installed capacity, the last row shows the annual cost considered in this paper.

2020	2030	2040	2050
550 000 NOK/MW	430 000 NOK/MW	400 000 NOK/MW	390 000 NOK/MW
55 mNOK	43 mNOK	40 mNOK	39 mNOK

Table 13: O&M costs for offshore wind from 2020-2050. Estimates from (De Vita et al., 2018)

7.3 Price Data

As the handling of the electricity price was presented in section 6, this subsection will provide estimates on natural gas, NOx cost and carbon prices.

Natural Gas Price

On behalf of the ministry of Petroleum and Energy, Rystad Energy (2020) has conducted an assessment of the Norwegian state's direct financial interest. This report is used for estimating prices of natural gas. Although a long term price of 2,5 NOK/Sm^3 is suggested, the report also provides more detailed estimates until 2040. In this thesis, the main scenario is applied[9], with values at select years seen in table 14.

Year	Natural Gas Price
2022	1,90 NOK/Sm^3
2025	2,60 NOK/Sm^3
2030	3,10 NOK/Sm^3
2040	3,78 NOK/Sm^3

Table 14: Gas prices at selected years (Rystad Energy, 2020)

Carbon Price

The carbon price levels applied for this study is based on the targets set by the Norwegian government's "Climate action plan 2021-2030"(Ministry of Climate and Environment, 2021a). We therefore assume the proposed 2000 NOK/TC level will be reached in 2030, with this happening through a gradual increase from today's level. Based on (The Norwegian Petroleum Directorate, 2020), we apply a starting value of 700 NOK/TC and linearize this value until the 2000-level in 2030. The development beyond 2030 is less clear and we therefore maintain a constant level for the remaining time periods. The value of the cost of NOx emissions is also based on (The Norwegian Petroleum Directorate, 2020), where a constant value of 22,69 NOK/kg NOx is advised.

[8] In table 13, we use 1EUR = 10NOK. We also use 2020 level for 2021

[9] An overview of the annual price levels for each scenario can be found in appendix C

7.4 Constants

Before starting the Hywind Tampen project, the alternative cost of implementing a PFS solution at the same site was investigated. The cost used in (Equinor, 2017) was based on guidelines from the government, which suggested a discount rate of 5%. Governmental treatment of petroleum investments are usually treated with a real interest rate of 7%, but in (The Norwegian Petroleum Directorate, 2020) the recommendation from the Ministry of Petroleum and Energy department is to also use a 5% discount rate. Based on the recommendations in the above-mentioned reports, we apply a discount rate of 5% in this study.

Petroleum companies on the NCS are subject to a regular corporate tax rate (22%), but also a special petroleum tax rate (56%) (The Norwegian Tax Administration, 2021). Although these may vary, historically the sum have been kept at 78% and is therefore used for the exported gas in the calculations. With such a high rate, there are mechanisms in place for deductions, meaning the rate may be lower. We do not consider the possibility of such deductions, and therefore apply the rate of 78% as a conservative estimate. Moreover, the sale of exported electricity from OW is subject to a corporate tax rate of 22%.

Our model setup does not include hourly, daily or monthly values for the wind conditions. To handle the intermittence of wind, we therefore include a capacity factor to obtain an annual level in the calculations. Based on the geographical coordinates and characteristics of the wind turbines, we obtain the capacity factor from historical data at the site using (Pfenninger and Staffell, 2021). As seen in figure 9, the factor varies throughout the year, but has an annual average of 58%. Given our annual time steps, we therefore apply a capacity factor of 58% in the calculations.

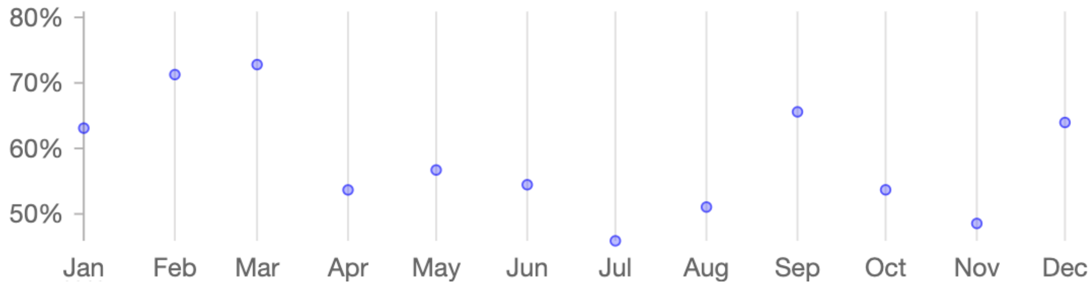


Figure 9: Capacity factor of wind turbines at the case location, obtained from (Pfenninger and Staffell, 2021).

This section has presented characteristics and information on a real life offshore installation in the Norwegian Sea. The field has an expected lifetime until 2040 and we allow for electrification either by installing a cable with 100MW capacity from shore and/or by installing an OWF with the same capacity. Due to the capacity factor, the PFS option will replace 42% more power on average. We have also presented the costs for exporting power beyond the lifetime of the field. This option is considered between 2041-2050. In addition, we have provided relevant cost data and price levels. All the presented information in this case represents the base case. Based on the input data from this section, we will analyse this case in the next section, where the results of our study are presented.

8 Results and Discussion

In this section, the results of our computational study are presented. First, initial findings from the base case (BC), as described in the previous section, are given. We then present the simulated electricity price levels corresponding to each identified option. Secondly, a breakdown of the cash flows for each option is given to provide an understanding of which factors are most determining for the investment decisions. This is followed by an assessment of the computational performance of the model, before we investigate the sensitivity of results to different scenarios. Based on these analyses, we aim to conclude on the value of applying a ROA in this thesis and for electrification investments in general. In the final subsection, we aim to summarize the implications of the results on our research questions. Specifically, we focus on answering the following questions throughout this section.

- Under what market conditions will investments in electrification of offshore O&G platforms be profitable?
- Will the decision to electrify be affected by also allowing for export of power produced from OW in a long-term perspective?
- Will applying a real options approach provide additional value to the decision makers, as opposed to traditional project valuation methods?

8.1 Results of Base Case

Here, we present the results of the BC, as described by the inputs from the previous section. When changing input parameters throughout this chapter, the findings from this first subsection will be used as a reference point. We regard the problem from 2021-2050, meaning $t \in \{0, ..., 29\}$. The MSIP problem in this study has been implemented using the MSPPy package (Ding et al., 2019) and solved using the SDDiP algorithm presented in section 6.3, where we run Monte Carlo simulations on the electricity price represented as a GBM. We find that this uncertain price processes is sufficiently represented using 20 Markov states based on an optimality gap stopping criteria. For each model run, a policy is obtained, which can be regarded as a function that maps given model states to decisions. We test the obtained policy by running 1000 simulations on the continuous true problem to obtain an estimated value for the NPV function and recommended decisions for each simulation. Throughout this section we differentiate between our three options using the following abbreviations

- PFS: Investment in PFS
- OW: Investment in OW for electrification
- EXP: Investment in OW to export power to shore

and apply the | symbol behind these if a previous option has been activated. For the simulated realizations of the uncertain price process, table 15 presents the amount of times each option was chosen, as well as the percentage of the total 1000 simulations.

Option(s) chosen	# of times the option is chosen	Percentage of total simulations
OW	923	92,3 %
EXP|OW	66	6,6%
PFS	11	1,1%

Table 15: Optimal investment strategies for 1000 simulations of the base case

In table 15, we observe a clear recommendation to invest in electrification using OW. This is found to be the optimal choice for 92,3% of simulated futures of the electricity price, whilst an additional 6,6% of simulations also suggests activating the export option beyond the lifetime of the O&G field. Effectively, this suggests making an investment in electrification using OW for 98,9% of simulated price processes. A small 1,1% of simulations finds investment in PFS to be optimal. This means that no price simulations suggested the optimal strategy to be EXP|PFS or taking on both electrification options. As mentioned above, we also obtain an estimate for the value of the NPV function. Given as a confidence interval (CI), we can be 90% confident that the expected NPV is in a region between [1427, 1693] million NOK (mNOK). We apply the mean of this CI as an estimate of the expected NPV, which gives 1560 mNOK.

8.1.1 Simulated Electricity Prices

Next, the focus is shifted towards the simulated electricity price levels for the three option paths found in the BC. For each, figures showing all simulated price trajectories are presented, followed by graphs showing the annual average and median prices. Before considering these, the price for the deterministic case is visualized in figure 10, where the price levels until 2050 are only dictated by the specified drift term of the GBM.

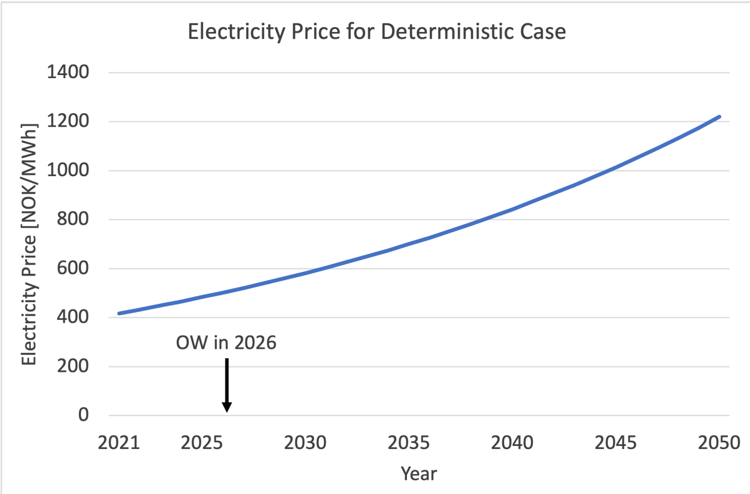


Figure 10: Electricity price for the deterministic case

In a deterministic setting, the optimal investment strategy is to only invest in OW, with this option activated in 2026. Prices follow an increase from the initial level of 417 NOK/MWh to 1219 NOK/MWh in 2050. The expected NPV for this case is 1201 mNOK, which is 29% less than the expected NPV when allowing for the uncertain price process.

Electrification using OW

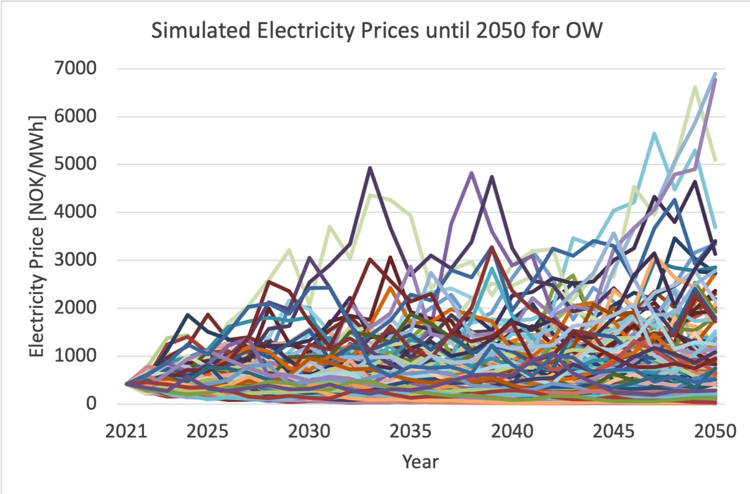


Figure 11: Simulated prices for OW-electrification

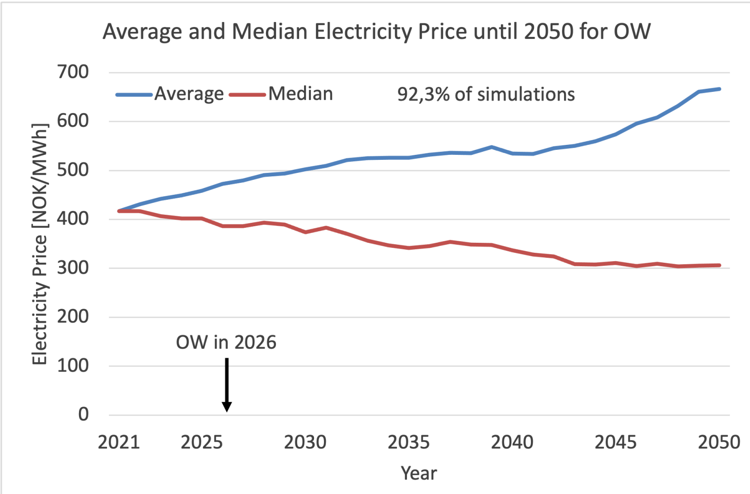


Figure 12: Average and median prices for OW-electrification

The first considered scenario is the dominant OW alternative, which is the optimal choice for 92,3% of price simulations. We note that this option is the only one whose cash flows are independent of the electricity price. All simulated developments until 2050 are seen in figure 11, while the annual average and median price curves are seen in figure 12. An interesting observation is that for every one the 923 simulations, the investment timing is set in 2026, which is the same as for the deterministic case. Furthermore, although a few spikes in the region of 5000 NOK/MWh are identified prior to 2040, the annual average value shows a steady upward trajectory ending just below 700 NOK/MWh, which is approximately 500 NOK/MWh less than the deterministic case. In addition, the annual median decreases, indicating that the highest simulated price levels are not included for this option.

Export of power, given previous electrification using OW

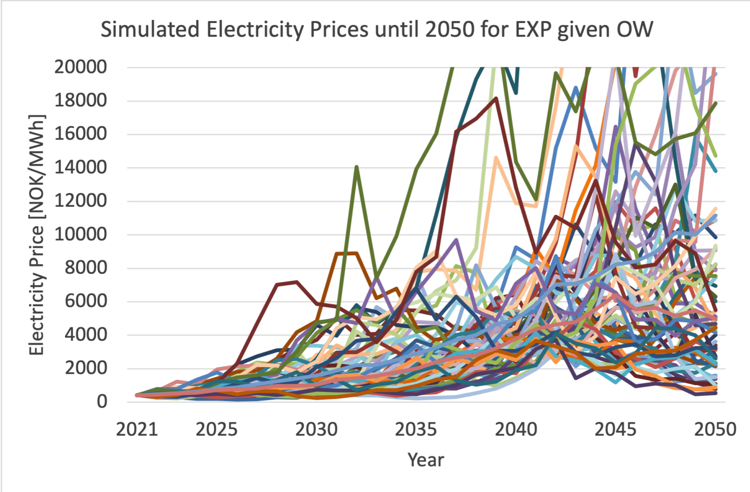


Figure 13: Simulated prices for export given OW-electrification

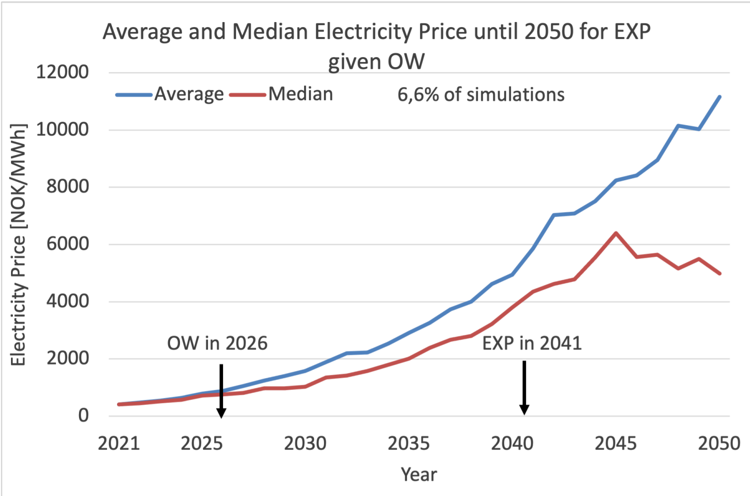


Figure 14: Average and median prices for export given OW-electrification

The EXP|OW option was found to be optimal for 6,6% of simulated electricity price levels, which can be seen in figures 13 and 14. The investment timing for OW remains in 2026 for all simulations. Some variations in timing of the export decision are observed, but the average is set in 2041, which is the earliest possible. The slope of the average curve is greatest between 2040 and 2043 and a jump in the lower regions of the simulated prices is also observed in this period. This indicates that a steep price increase around 2040 contributes to the activation of the export option. Beyond 2040, the average price exceeds 6000NOK/MWh, with values beyond 10000 NOK/MWh towards 2050. The average and median curves show considerably higher values than the OW-case. In fact, when averaging the electricity price for each simulation, 62% of EXP|OW-levels are greater than the maximum for OW and all simulated EXP|OW-levels are greater than 89% of the simulated averages for OW. This indicates that the decision to export is taken for the highest price trajectories.

Electrification using PFS

Finally, we present the 1,1% of simulations suggesting electrification using PFS as the optimal decision. In figures 15 and 16, we observe that the option is activated after a steep price decline in the earliest time periods. The average investment timing is set in 2025, which is just prior to the minimum point of the average and median curves. Beyond, a price increase is observed, but with levels well below those observed for the other options.

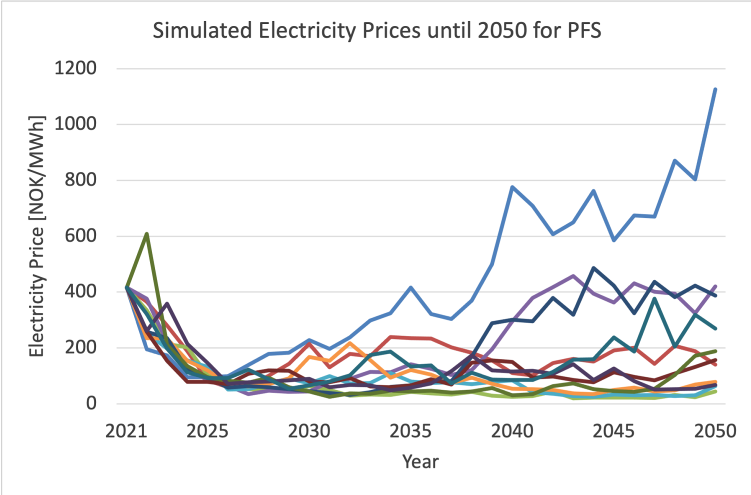


Figure 15: Simulated prices for electrification using PFS

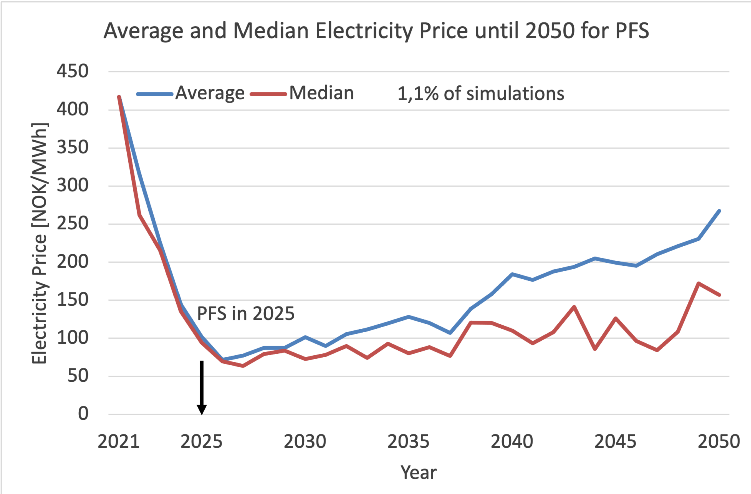


Figure 16: Average and median prices for electrification using PFS

To conclude this subsection, the recommended decision is to only electrify using OW, with this investment set to happen in 2026. The highest price trajectories beyond 2040 also recommended activating the option allowing for exporting power to shore, which was the case for 6,6% of simulations. Finally, the PFS option was only recommended for 1,1% of simulations and for average price levels below the other options.

8.1.2 Breakdown of Cash Flows

Next, the contributions of each component in the revenue and OPEX streams are presented. As the OW-electrification alternative is the most dominant, we first provide a complete breakdown of each component over the period the option is available. This is followed by a comparison between using the simulated price levels and deterministic forecasts for both PFS and EXP|OW alternatives.

Even though the suggested investment timing is not until 2026, figure 17 shows the total cash flows from 2021-2040 for OW. The solution represents replacing a maximum of 100MW between 2021-2033 and 75MW from 2034-2040. Due to the capacity factor for OW, only 58% of these are actually replaced on average. We note that the increase in the carbon price provides an increasingly positive contribution to the cash flows until 2030. This price level is held constant beyond 2030, but the contribution decreases in 2035 and 2040 as there is less power available for electrification.

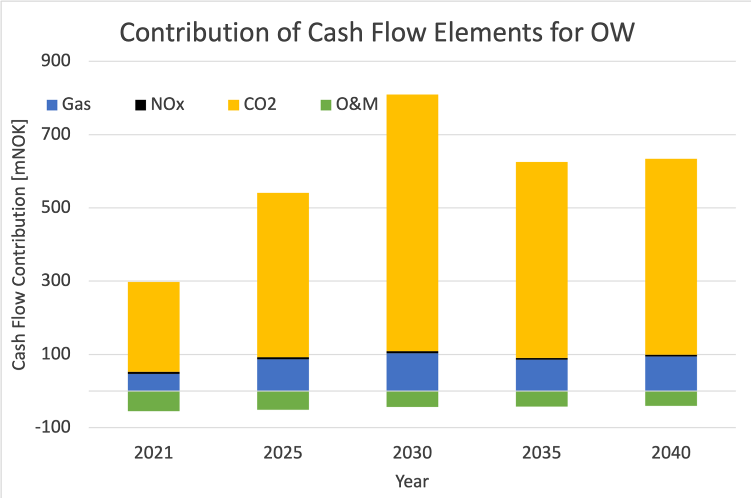


Figure 17: Cash flows for OW-electrification option

The revenue from the sale of freed gas is the second largest contributor, but still relatively small in comparison with the saved carbon charges. An increase is observed between 2021 and 2030 as the natural gas price increases. However, the total increase in contribution to positive cash flows from 2026-2040 is from 12% to 15%. In that period, the actual gas price increase is 45%, which indicates that variations in the price level has a relatively small impact on total cash flows. Furthermore, the cost of O&M represents an even smaller contribution, while the savings in NOx charges are negligible.

In the previous subsection, the results indicated that the PFS option was activated under the lowest simulated electricity prices, whilst the EXP|OW option was activated under high price levels beyond 2040. For each of these, the cash flow distribution is compared with cases applying the deterministic electricity price level from figure 10. As the PFS option was activated in 2025, comparisons are made at this point, as well as in 2030. The result is seen in figure 18.

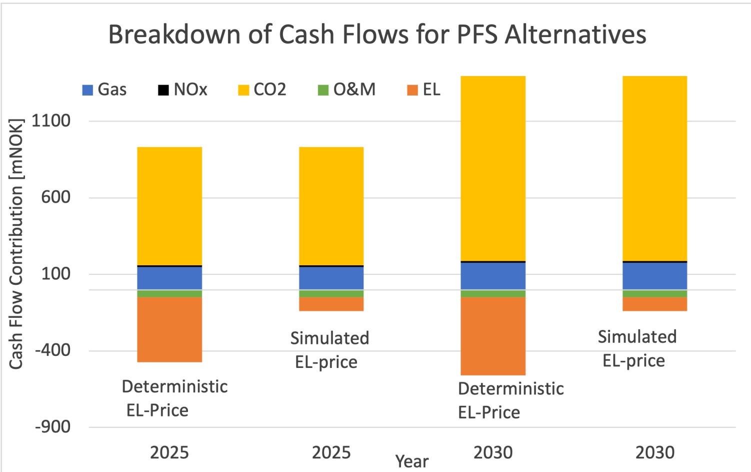


Figure 18: Distribution of cash flow elements for the PFS option. Comparison between cases of deterministic price levels and prices from simulated cases

The contribution from saved carbon charges and sale of gas has a similar development from 2025 to 2030 as for the OW case. The point of difference is that 42% more power is replaced, due to the capacity factor of wind. However, a significant amount of this is offset by the cost of the supplied electricity in the deterministic case. For the majority of simulated cases, the higher portion of saved carbon charges were not sufficient to warrant investments in PFS. By comparing the deterministic and simulated cases, we obtain an indication of the required reduction in the electricity cost for the option to be activated.

Next, figure 19 shows the same comparison for EXP|OW in 2041 and 2050. The effect of the high electricity price levels required to activate the export option can be observed when comparing the simulated case with the deterministic one. The already large difference in revenue from sale of electricity in 2041 is further increased towards 2050. Similarly as for the PFS case, the differences between the simulated and deterministic cases serves as an indicator of why these options are chosen for only a small percentage of simulations. If this study had considered periods beyond 2050, it is likely that the required contribution from the sale of electricity to activate the export option would have been less. As a result, this could lower the electricity price threshold for making the investment.

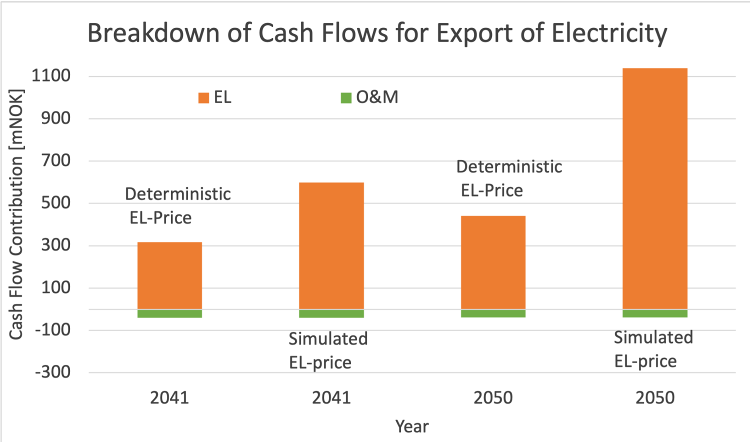


Figure 19: Cash Flows for Export given OW. Comparison between cases of deterministic price levels and prices from simulated cases

We have observed that all simulations that found OW as the optimal decision suggested the same investment timing as the deterministic case. That is, investment in OW in 2026. To investigate this, we plot both the annual cash flows for the OW option and the strike price from 2021 until 2040.

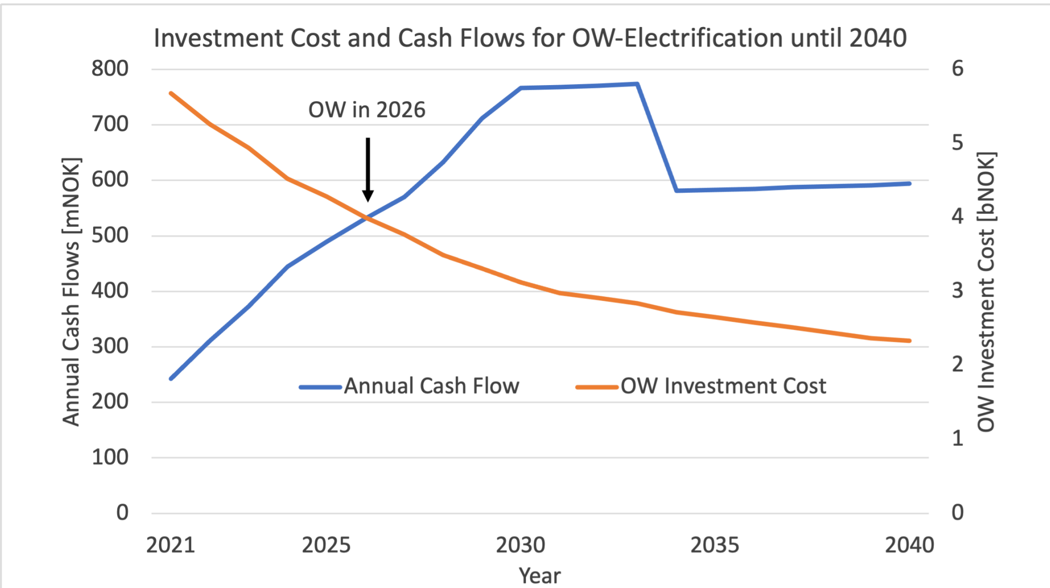


Figure 20: Annual cash flows and investment cost for OW-electrification until 2040

Figure 20 provides an indication of the relationship between the cash flows and investment cost for the OW option. Due to the applied learning rate of floating OW, we observe that at time of investment, this cost has reduced by 30%, whilst the cash flow has increased with 119% from the initial period. We previously observed the dominant contribution from saved carbon costs. The effect of gradually higher carbon prices until 2030 can therefore be observed in the steep increase of the cash flows. Thus, the timing indicates that in 2026 it becomes more profitable to capture the increasing savings in carbon costs, than to wait for a further decrease in the strike price. Further analysis on the optimal strategy's sensitivity to changes in both these elements will be presented later, but an initial indication is that these are two important factors for the investment timing.

8.2 Computational Performance

The formulated MSIP problem is solved by means of the SDDiP algorithm presented in section 6.3. There, we distinguished between a true problem and the discretized one. We start by defining a true problem, which is specified in accordance with the optimization model and by letting the electricity price follow a GBM. Next, this continuous problem is discretized using stochastic approximation (Ding et al., 2019). When applying the previously presented steps of the SDDiP algorithm on the discretized problem, we obtain an optimal policy for this distribution. This policy is then evaluated back on the true problem to receive the expected NPV, which was presented in the subsection above. In this subsection, we investigate the performance of the model run when obtaining these policies. We therefore emphasize that the values of the objective function presented here are related to the discretized problem, not the true one. To capture convergence, we have applied a stopping criterion based on the idea of an optimality gap, which is the difference between the best known solution and a value that bounds the best possible solution. The best known solution is the upper end of a 95% CI of the value of the discretized problem, while the lower bound is found from simulations. Every three iterations the constructed policy value is evaluated on the discretized problem by employing a 1000 Monte Carlo simulations. For each simulation, a sample path is generated independently from the discretized problem, leading to an optimal value and policy solution. The algorithm stops when we are 95% confident that the optimality gap is less than a specified tolerance of 1%. Outputs from the evaluation on the discretized problem for different amounts of Markov states are shown in table 16.

Markov States	Iterations	Time	Bound [mNOK]	Opt Gap	EPV [mNOK]	CI-95 [mNOK]
1	6	0,59 sec	1201	0%	1201	[1201, 1201]
2	6	0,97 sec	1201	0%	1201	[1201, 1201]
5	12	4,52 sec	1203	0,01%	1214,5	[1204, 1225]
8	18	21,26 sec	1206	0,78%	1208	[1197, 1219]
10	18	13,04 sec	1208	0,71%	1210,5	[1199, 1222]
15	12	13,62 sec	1217	0,42%	1222	[1212, 1232]
20	12	16,86 sec	1218	0,75%	1220	[1209, 1231]
50	> 493	$>$ 1 hour	1307	3,1%	1293	[1267, 1319]
100	> 316	$>$ 1 hour	1324	4,09%	1297,5	[1270, 1325]

Table 16: Computational results for different amounts of Markov states

When increasing the number of Markov States, we attempt to provide a more detailed representation of the uncertain process. For a specified amount of states, table 16 displays number of iterations needed to obtain convergence, total run time, a deterministic upper bound, the value of the optimality gap, expected policy value (EPV) and the 95% CI of this policy value. This EPV is given as the mean of the CI. We observe an optimality gap less than 1% for all simulation until 20 Markov states. The spread in the optimality gap is shown for 20 states in figure 21, where we observe convergence after 12 iterations. When increasing the amount of states to 50 and 100, we observe a greater optimality gap, meaning we do not obtain convergence for the specified tolerance level. We have run both processes for one hour, which took 493 and 316 iterations for the cases of 50 and 100 states, respectively. Despite this, the optimality gap remained unchanged and we did not find that the obtained solution improves beyond 12 iterations. Had the model been run for longer a time, we may have achieved convergence according to the 1% optimality gap eventually. As such an approach would be computationally expensive and time consuming we choose 20 Markov states for our model runs. Given the specified tolerance level for the optimality gap, we consider this to sufficiently represent the stochastic electricity process.

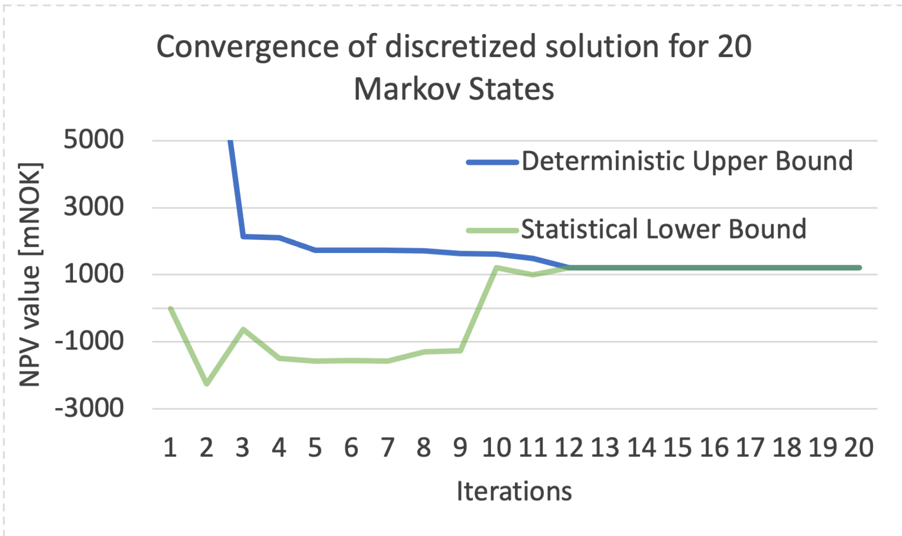


Figure 21: Convergence for simulations when using 20 Markov states

Figure 21 shows the effect of each iteration for 20 Markov states. We observe that the upper bound found from the forward passes quickly approaches the final value, whilst the statistical bound requires approximately 10 iterations to obtain a positive solution. Although there remains a 0,75% optimality gap, the problem converges relatively easy. This is also reflected in a computational time of 16,86 seconds. Thus, the calculations are not viewed to be computationally expensive. Later, we will discuss the possibility of including more uncertain processes, which is likely to increase the complexity of the problem. The fact that this is solved without too much computational effort indicates that we may investigate expanding this setup.

8.3 Sensitivity Analysis

With the BC results established, this section will apply sensitivity analyses to determine which conditions have the greatest impact on the profitability of electrification projects. Therefore, we investigate the effect on the optimal investment strategy when varying input data. We test for increasing levels of volatility in the electricity price, varying carbon price scenarios and investigate the effect of changes in investment costs. In addition, we restrict the export option to provide an estimate of the additional value of including this option. Throughout this subsection we also discuss the implications of the BC results to a greater extent.

8.3.1 Volatility in the Electricity Price

In the BC, the decision to electrify using OW was taken for 98,9% of simulated electricity price scenarios. As 92,3% of these recommended an option that is independent of the price of electricity, it becomes interesting to investigate whether the optimal investment strategy is sensitive to greater variations in the electricity price. An important assumption made was to model the electricity price as a GBM. Working with this assumption, the drift and diffusion parameters were estimated based on historical data, which gave a standard deviation of log-returns of 29%. Taking a selective extract of the wholesale electricity price from the past 18 months (April 2020 - October 2021), we observe changes from a region of 40-70 NOK/MWh up to 400-700 NOK/MWh. A tenfold increase in this period illustrates that the volatility may in fact be larger than was suggested by the historical data. Given the pressures to alter energy production to meet climate targets, major upheavals can happen in the market for electricity. As such, relying on historical data is not necessarily an accurate representation of the future. Therefore, we investigate the effect of increasing the volatility of the electricity price. In addition, we view the increase in volatility as a representation of a more uncertain future. As such, the response to the increased uncertainty may also provide insight into the value of applying a ROA to this problem. As the deterministic case with zero volatility gave OW-electrification in 2026 as the optimal solution, lower values for volatility are not considered. Instead calculations are performed for levels of 40-60-70-80%, with results found in table 17.

Volatility	$\sigma = 29\%$	$\sigma = 40\%$	$\sigma = 50\%$	$\sigma = 60\%$	$\sigma = 70\%$	$\sigma = 80\ \%$
PFS	1,1%	10,2%	20,8%	36%	48,1%	60,1%
OW	92,3%	81,1%	72,4%	59,5%	48,9%	38%
EXP|OW	6,6%	6,4%	6,2%	4%	2,4%	0,9%
EXP|PFS	-	0,5%	0,6%	0,5%	0,6%	1%
$\text{NPV}_{90\%}$ [mNOK]	1427-1693	1610-2229	1773-2810	1783-3184	1806-3323	1450-2594
$\Delta\text{NPV}_{90\%}$	-	23%	47%	59%	64%	30%

Table 17: Simulated option choices for increasing levels of volatility in the electricity price

The initial impression is that the optimal strategy is sensitive to increased volatility in the electricity price. The most distinct change is found for an increase in cases suggesting the PFS option. Per 10% increase in the volatility, there is an average increase of 12% more PFS cases and 11% less OW cases. The BC results showed that the price had to reach low levels to trigger the PFS investment. The resulting changes when increasing volatility can be explained by our assumption of allowing the price to follow a GBM. In particular, the effect of the positive drift term is offset by an increasingly large σ^2 term in equation 25. In addition, the impact of the random diffusion term is greater, which may contribute to the increased spread in the 90% CI in table 17. For all volatility levels until 70%, the recommended decision remains to invest in OW. However, a shift towards PFS as the optimal strategy is observed when volatility increases to 80%. Further analysis reveals the first case of more than half of the simulations recommending PFS is found for a volatility of 74%. Given the potential changes in the entire European power market when transitioning into less emitting alternatives, we may be faced with an increasingly volatile future. Additionally, the potential effect of climate change with more extreme weather conditions may cause larger variations in this regard as well. This discussion illustrates that although the BC results shows a clear recommendation of investing in OW, that decision is subject to the assumptions made with regards to the GBM and the calculations of parameter inputs. Applying a longer or shorter time period for historical data or basing calculations of forward curves or implied volatility may result in different input levels.

As the cash flows related to the OW option are independent of the electricity price, changes in the recommended strategy due to greater volatility results in an increase of the estimated NPV. If not, the optimal strategy would still be to activate the OW option. This increase in profitability is observed in the 90% CI of the NPV function. The range of this interval increases with more volatility, indicating less accurate estimates are obtained. The $\Delta\text{NPV}_{90\%}$ seen in table 17 is calculated as the percentage change of the differences in mean of each CI. This change in NPV should therefore not be considered an exact measurement, but indicates the sensitivity to the increased volatility. Here, the average profitability increases for higher levels of volatility, but between 70-80% this increase is reduced.

Moreover, increased volatility in the electricity price does not suggest a later investment time. In fact, the suggested investments involving PFS are taken in 2022 and 2023, whereas the BC simulations for PFS suggested 2025. For the cases for OW-electrification, the average investment timing is still 2026 for all simulations. For σ between 60-80% we observe a few cases of later investment in OW, but the occurrences of these are set below 3% of the total OW simulations and are therefore not considered significant enough to suggest a trend. This indicates that the operating firm will not want to await an OW decision to obtain more information on increasingly volatile electricity price futures.

In conclusion, we observe that increased volatility shifts the recommendation from OW to PFS and increases expected profitability. From an initial level of 29%, a majority of cases suggesting PFS investment is found for a volatility of 74%. Despite this, we do not find indications that the decision makers will want to deter OW investment in a more a volatile electricity price future.

8.3.2 Restricting the Export option

Next, we attempt to estimate the additional value from including the possibility of exporting power to shore after the field's lifetime. With only 6,6% of simulations advising for export given OW and none given PFS, we question if the inclusion of the export option provides additional value. To investigate this, the export option is restricted and made unavailable for the entire period. Therefore, the analysis here only considers the two electrification option from 2021 until 2040.

An estimate of the value of the export option is found by comparing the NPV functions for the BC with the restricted case. For the latter, the 90% CI is found to be [1107, 1155] mNOK. By subtracting the bounds of each case with each other we obtain an interval of [316, 538] mNOK. This is therefore used as a rough estimate of the additional value from allowing for export. Moreover, we observe a shift from 1,1% to 10,6% of investments for PFS, while the remaining 89,4% are for OW. In the BC, the highest price levels beyond 2040 meant profits could be captured from exporting power. As these are not considered here, we instead observe that the PFS option is activated for higher price levels. Another point of discussion is whether the additional value is affiliated with export given PFS or OW. In the BC, we found indications that PFS favored low price levels, whilst EXP was activated for higher prices. Although the export only considers prices beyond 2040 and prices may vary over the lifetime, these opposites suggest that the additional value is mainly associated with EXP|OW. Based on this, the decrease in project value from excluding the export option is mainly affiliated with not being able to export after an OW investment.

We therefore conclude that including an export option beyond the field's lifetime does add value to the investor. However, the export option is favored for cases where OW-electrification itself is profitable and we may activate the export option when prices are high. For PFS, we do not consider the export option to add much additional value for the decision maker. Finally, our focus area was not only whether it adds value, but also whether it changes the decisions. Although there was an increase in simulations recommending PFS, the optimal course of action would've still been to invest in OW for electrification. Therefore, it is found to add value, but not to alter the recommended course of action.

8.3.3 Investment Costs

This subsection will consider the sensitivity of the investment costs for both electrification options. Given the differences in maturity of technology for these options, we consider estimates for OW to be more uncertain than for PFS. In addition, while the PFS estimates are based on the actual case, the costs for OW are based on a similar one. Therefore, this sensitivity analysis will place more emphasis on the development of the OW cost. As seen in section 7, the costs for the export option are based on the assumption of shared infrastructure between options. When altering investment costs, the export cost will therefore be changed in accordance with previous assumptions. These cost changes are not presented, but are included in the calculations.

Strike Price of OW

For the strike of the OW option, we do not consider scenarios of lower prices. This is a result of the large portion of OW cases, meaning a lower cost is likely to increase this portion without providing new information. Instead, the strike price is increased according to the following scenarios.

- 10%: Increase the initial strike price by 10%, but letting the OW cost follow the same learning rate as in the base case.
- 20%: Increase the initial strike price by 20%, but letting the OW cost follow the same learning rate as in the base case.
- Reduced Learning (RL): Maintaining the initial cost from the base case, but reducing the learning rate by half in each period.
- Constant (Const): Having a learning rate of zero, meaning constant strike price of 5,68 bNOK.

	BC	10%	20%	RL	Const
PFS	1,1%	4,3%	8 %	7,4%	11,2%
OW	92,3%	88,9%	82,8%	85,9%	82,1%
EXP|PFS	-	0,1%	0,1%	-	0,1%
EXP|OW	6,6%	6,7%	6,7%	6,7%	6,6%
OW|PFS	-	-	2,2%	-	-
EXP|{PFS∧OW}	-	-	0,2%	-	-
$NPV_{90\%}$ [mNOK]	1427-1693	1121-1387	737-1019	862-1129	393-662
Δ $NPV_{90\%}$	-	-16%	-44%	-36%	-66%

Table 18: Results of changing the investment cost of OW

In table 18, we observe an increase in cases of PFS and decrease in OW when the OW strike price increases. Despite this, the sum of OW and EXP|OW is still above 90% for every simulation, with an exception for the constant cost (88,7%). It therefore becomes more interesting to analyse the effect on profitability. Again, we apply the mean of a 90% CI of the expected NPV as an estimate, which can be seen in figure 22.

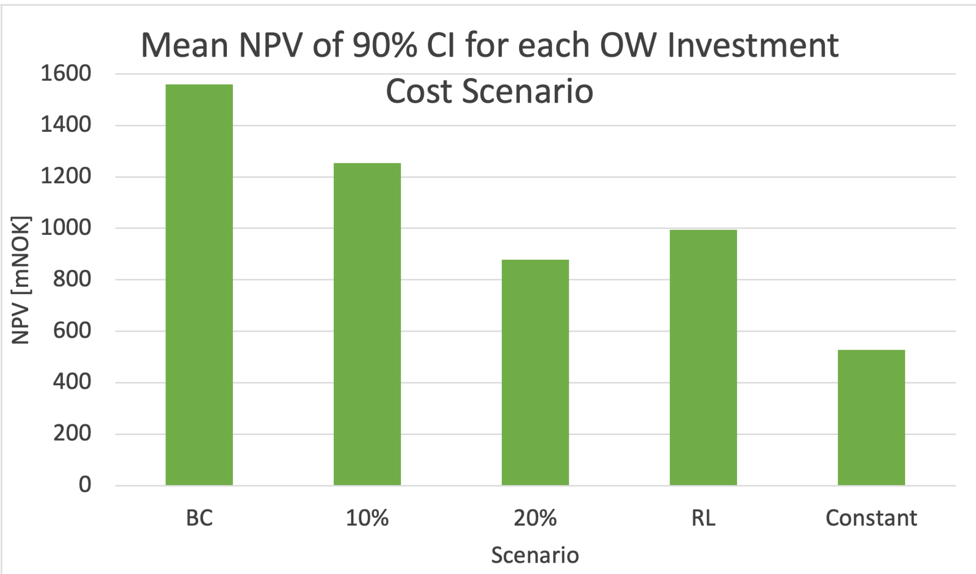


Figure 22: Mean NPV of 90% confidence interval (CI) for each cost scenario

Until this point, we have observed changes in which decision to make, but less for whether the investment should actually be made. The increase in strike prices is seen to reduce the margin for investment when applying a positive NPV decision rule. This is observed with respective reductions of 16% and 44% for the 10% and 20% increase. Although the suggested decision remains to invest in OW, a close to halved NPV for the latter suggests that the profitability is sensitive to changes in the strike price. Given that our investment cost estimates for OW are not case specific, it may be reasonable to add a safety margin to account for the uncertainties in estimates. As such, the large decrease in expected NPV would suggest that we may be closer to not making the investment than the values in figure 22 would suggest.

In addition, we test the effect of the applied learning rate by the inclusion of the reduced learning and constant scenarios. In the literature review on project valuation of OW, we referenced Schwanitz and Wierling (2016), who claimed over-optimistic assumptions on learning rates create biases in the valuation of investments in OW. In particular, they criticise the assumption of learning effects leading to reduced costs over the lifetime of the project. This assumption is present in the BC, both in terms of investment cost and O&M costs. In the critique, a main point was that the increased magnitude, complexity and power generation capacity of OW projects set to be initiated may in fact be a significant source of cost increases. The Hywind Tampen case, which we base our calculations on, is set to be the world's largest offshore floating wind farm. As such, it could be affected by the above-mentioned elements. As it develops, there may be operational difficulties causing delays or other unforeseen events leading to increased costs. As the project is yet to be in operation, the cost of 5 bNOK for 88MW capacity may in fact grow larger. This makes it interesting to investigate if there are benefits associated with awaiting a decision to learn the outcome of similar projects or whether we should initiate projects under an assumption of reduced costs from "learning-by-doing".

We therefore consider the investment timing of each scenario. For both the 10% increase and reduced learning scenarios, the timing remains unchanged from the base case, meaning OW investment in 2026. The situation differs for the two other scenarios. The 20% increase did not advise for the OW option before 2028, which suggests we wait until the learning rate has reduced the cost further. The slope of the learning curve is steepest until 2025, but does not change much until 2030. As such, by waiting two more years, the optimal timing allows for significant reductions in the strike price. However, later investment means less cash flow is captured, which is observed in the reduced NPV. For the case of a constant investment cost, there were fewer investment in OW, with an average exercise time in 2023. Based on these variations, we conclude that the investment timing is sensitive to both the assumed learning rate and cost estimates. As our estimates are not case specific, but based on similarities with the Hywind Tampen case, we acknowledge that this is a source of uncertainty in the results. In addition, the learning rate is also based on the development of floating OW in general, and not for the specific conditions at the case site. Therefore, we view further work on obtaining accurate estimates on the strike price of OW for this case to have potential for improving the accuracy of our findings.

Strike Price of PFS

Next, we consider the investment cost of installing PFS. Although the estimated costs are provided from the operator on the case in question, investments of this scale are inherently uncertain. We therefore estimate the effect of a 10% and 20% decrease in the investment cost.

	BC	10%	20%
PFS	1,1%	11,5%	18,4 %
OW	92,3%	78,5%	60,7%
EXP|PFS	-	1,7%	11,8%
EXP|OW	6,6%	8,3%	9,1%
$NPV_{90\%}$ [mNOK]	1427-1693	1468-1741	1638-1919
$\Delta NPV_{90\%}$	-	3%	14%

Table 19: Results of changing the investment cost of PFS

Although the amount of cases for OW is reduced with a corresponding increase in PFS cases, the simulations still favors the OW option as can be seen in table 19. Compared to the analysis of the OW cost, there are considerably less changes in the NPV calculations. We observe a 3% and 14% increase for the 10% and 20% cost reductions, respectively. No changes in investment timing are observed. In terms of profitability, the NPV function appears to be more sensitive to changes in the strike price of OW rather than PFS. This again strengthens the point made of the importance of accurately modelling the dynamics of the OW cost when aiming to make profitable electrification investments. We have previously observed a small amount of simulations recommending EXP|PFS. As we maintain the assumption of shared infrastructure, reduced PFS cost allows for the PFS option to be activated for higher electricity price levels, which in turn makes it more likely that they will increase sufficiently towards levels required for export in 2041. We observe this through an increase from no instances in the BC to 11,8% of simulation for the 20% cost increase scenario. Despite this, the recommended decision remains to invest in OW in 2026. We therefore consider the strike of PFS to affect profitability, but view the cost of OW to have a larger impact.

In conclusion, the overall decision to invest in OW shows little sensitivity to the investigated changes. However, interesting effects on both investment timing and profitability were observed for the OW case. Given the resulting changes in NPV, we find that the profitability is more sensitive to increases in the cost of OW than for decreases in PFS. In addition, we also observed that the changes in the assumed learning rate impacted both timing and profitability. We therefore consider more research on the expected costs for the case in question to be an area of improvement. Finally, the different scenarios of OW revealed the investment timing's sensitivity to the development of the investment cost. Given the immaturity of floating OW, this development is uncertain, but represents an important part of further discussions on the value of applying RO to electrification investments.

8.3.4 Carbon Price

When breaking down the components in the cash flows for the electrification options, saved carbon costs was found to be the dominant contributor. We will therefore apply scenario analysis to investigate the effect of various future developments of carbon prices. In the background section in figure 5, four EU ETS trajectories for meeting targets set in the Paris agreement were presented. To investigate futures where such goals are met, three of these scenarios are included in this analysis. A more thorough review of each scenario is found in (Auer et al., 2020), but important underlying assumptions for each are presented here. In addition, a scenario accounting for continuous carbon price growth beyond the 2030 level of 2000 NOK/TC is included.

- Techno-Friendly (TF): This scenario accounts for meeting the 1,5°C goal and assumes a positive societal attitudes towards lowering GHG emissions. As such, new technologies, including floating OW, will be more easily adopted in society. The scenario does not consider a high degree of governmental influence and assumes that societal opinion drives industrial actors towards developing emission reducing technology.
- Directed Transition (DT): A scenario applying the highest carbon prices considered and accounting for the 1,5°C goal. This storyline assumes little effect of citizen-led initiatives and relies on strong political involvement. By creating heavily incentivized frameworks, the industry will transition into low-carbon technology solutions.
- Gradual Development (GD): Accounts for the 2°C goal, by placing equal emphasis on both technological development, policy action and societal commitment towards reducing emissions. It envisions that each of these efforts are increased from today's levels.
- Continuous Growth (CG): Based on similar assumptions as the estimate used for the BC, but applies a linear price increase beyond 2030. In comparison with the above-mentioned scenarios, we assume this is established through incentives from policy makers. The linear increase is therefore led by a high degree of political involvement, which provides the industry with the predictability needed to develop technology in accordance with increased charges.

No particular assumptions are made on the degree of societal commitment or whether this contributes to reaching targets set in the Paris agreement.

As the first three scenarios are not specific to the NCS, a lower bound of 700 NOK/TC has been placed to ensure that values more accurately represent the situation for our case study. All scenarios, including the values used in the BC, can be seen in figure 23, with results from the analysis found in table 20.

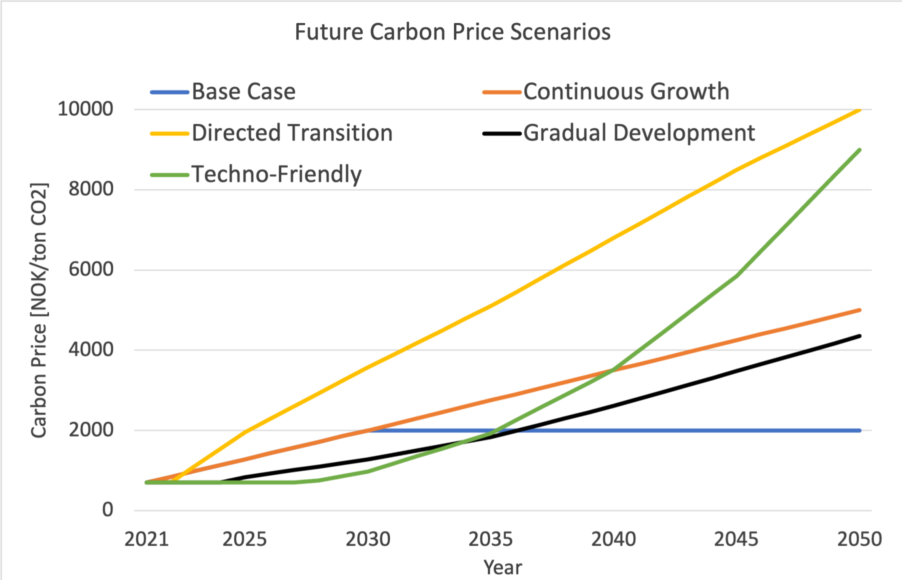


Figure 23: Carbon price from 2021-2050 for each scenario considered in the analysis

	BC	CG	TF	GD	DT
PFS	1,1%	12,8%	-	-	64%
OW	92,3%	80,3%	93,4%	92,3%	21,5%
EXP|PFS	-	0,4%	-	-	9,2%
EXP|OW	6,6%	6,5%	6,6%	6,7%	4,4 &
OW|PFS	-	-	-	1%	-
EXP|{PFS∧OW}	-	-	-	-	0,9%
$NPV_{90\%}$ [mNOK]	1427-1693	2520-2789	799-1064	618-888	9320-9634
$\Delta NPV_{90\%}$	-	70 %	-40 %	-48%	507,5%

Table 20: Results of scenarios analysis for carbon price

An interesting observation for the gradual development and techno-friendly scenarios is that although their respective values in 2050 are as high as 4000 and 9000 NOK/MWh, their calculated NPV functions shows 48% and 40% reductions compared to the BC. The explanation is that their carbon prices do not exceed the 2000-level until 2036. Although there is a significant increase beyond this point, the field is expected to be shut down in 2040, meaning no electrification is considered beyond. In addition, less power can be replaced after 2033, which highlights the value of having high carbon prices in earlier time periods to increase the cash flow contribution. It therefore becomes apparent that an increase in carbon prices over the considered time period does not ensure increased profitability, but with this increase occurring in earlier periods there may be more benefits to the cash flows of the electrification projects.

The highest price levels are found in the directed transition, which passes the 2000-level in 2025 and continues this increase beyond. The large price increase is reflected in a substantial shift in suggested investment decision of 64% simulations of PFS and only 21,5% for OW. In addition, there is an increase in the option to export given PFS, meaning there would be investments in PFS for a total of 73,2% of simulated futures. As PFS represents the option replacing the most offshore GHG emissions, increasing carbon charges offsets the electricity cost to a greater extent than in previous cases. This is reflected in an increase of 508% in expected NPV. The other example of an increase in profitability is found for the continuous growth, which gave a 70% increase in NPV. Here, the shift from OW to PFS is much less, with still 80% of simulated futures suggesting OW. The variations in the NPV for the different scenarios illustrate that the profitability of electrification projects show a high degree of sensitivity to the future development of the carbon price.

Next, some observations on investment timing are provided. Given similarities to the BC, no changes in time of investment is observed for the case of continuous growth, while for the directed transition the optimal timing for both PFS and OW are found a year earlier than for the BC. More interestingly, we observe a delayed timing for both the gradual development and techno-friendly scenarios. The former finds optimal timing in 2028, while the latter in 2030, again emphasizing the importance of price increases in the first considered periods.

The above-mentioned results provides a clear indication that increased carbon prices results in more profitable electrification investment. Although that relationships holds when assessing the problem based on NPV decision criteria, it is important to note that on average only 3% of the total daily exported gas is used in the offshore GT. As such, the isolated operations concerning electrification may have positive cash flows, but the profitability of the platforms itself may be heavily reduced. If carbon price levels become too high, production costs may increase, which is reflected in higher gas prices. This could lead to a significant decrease in the demand for natural gas. This demand will be determining for the entire operation of the field, and thus whether or not emission reducing measures can be applied. Until 2030, the European gas demand is projected to remain stable or with a slight decrease (Catuti et al., 2019). Towards 2050, estimates are more uncertain and are heavily dependent on assumed GHG reduction target set. The above discussion illustrates that initiating an investment is not as straightforward as evaluating profitability. The potential escalation of carbon prices will potentially have greater repercussions than making electrification more profitable.

The analysis revealed that higher growth in carbon prices before 2030 increases the profitability of the considered investments. Focusing on the underlying assumptions for the investigated scenarios, we observe that the GD and TF cases relying on societal commitment and industry responses to this commitment makes the electrification investment less profitable. On the other hand, the BC, CG and DT are built on assumptions of more active involvement from policy makers. These scenarios assume a rapid increase of carbon prices, which results in higher profitability. The TF or GD scenarios are not claimed to be unfavorable for emission reducing measures in general, but are found to be less profitable for the case considered here. This indicates that active policy exertion with incentives-based policies may lead to a more rapid price increase, thus enabling investors to capture larger cash flows in the time periods before 2030.

To summarize, we have found that both profitability and optimal decision choices show a high degree of sensitivity to the future developments in the carbon price. However, the correlation between higher carbon prices and profitability has a ceiling as these carbon charges will impact the overall operating of the platforms. An attempt to quantify this level was not made, as that would lead to an entirely new discussion on the viability of the O&G industry in the face of increased carbon costs, which is beyond the scope of this thesis. We have found that a rapid increase in carbon prices may increase profitability, and that this increase is most likely to occur in futures with active political involvement.

Finally, the discussions in this section provides a research contribution in two regards. Firstly, as mentioned in the literature review, previous works evaluating electrification measures are operating with more conservative developments of the carbon price. Although the presented scenarios in this section are hypothetical, they serve to illustrate that if the set climate targets are to be met, drastic changes are expected. We therefore view applying updated scenarios as a possibility for enhancing the relevance of previous works. Secondly, the discussion has also illustrated the importance of considering the role of political actors. In the next subsection, we attempt to provide a conclusion on the value of applying a ROA to this problem. In this regard, the importance of carbon pricing will be used to illustrate how the inclusion of political uncertainty in a RO model can be beneficial for evaluating electrification projects.

8.4 Real Option Value

The literature review identified limited applications of RO to investments in electrification. This was the starting point for the objective to determine if such an approach could be beneficial for firms considering investments in electrification. Based on the results presented throughout this chapter, we will in this subsection attempt to provide a final conclusion on whether our approach has provided additional value compared to traditional project valuation methods. In addition, we aim to provide a research contribution by evaluating the potential of taking a ROA to electrification investments in general.

The first element in the sensitivity analysis was the volatility of the electricity price, where increased levels resulted in more cases suggesting the PFS option. However, no indication of increased volatility leading to postponement of investment was found. The majority of cases gave the same recommended decisions and investment timing as for the deterministic case. As a result of these observations, we inferred that there is little additional value in allowing for flexibility and awaiting a decision at more informed stage. Consequently, this reduces the value of applying a ROA for our specific case. The main contribution from our setup, as opposed to a deterministic approach, is the additional value obtained when allowing for export in a long-term perspective. We attributed this value to the potential of activating the export option under high electricity price futures. Although both the deterministic and simulated NPV functions gave values suggesting investments in OW in 2026, we found a 29% increase in expected NPV for our case. This estimated increase is based on the mean of a 90% CI and should therefore not be considered exact, but serves to illustrate the increased value when allowing for uncertainty. In a situation where the deterministic NPV had been closer to zero, this additional value could've been decisive in making the optimal choice.

A critique of our model formulation is aimed at the simplification of assuming the effect on cash flow is immediate when the option is activated. The installation of cables, the production of wind turbines and offshore modifications for both options means there is a time span before the effect on cash flows can be observed. For PFS, the operator estimated a period of four years from the decision is taken to a fully operative state. Given that cables do not need to be installed, the OW option might be less time consuming, but the immaturity of technology makes it unlikely that the instalment time will largely differ from the PFS case. In the BC, the optimal investment timing was set in 2026. In reality, the impact on cash flows could then happen around 2030. With only 10 years to receive cash flows and with the offshore power demand decreasing beyond 2033, it becomes increasingly difficult to justify such an investment. As a result, the expected NPV found in this thesis is likely overestimated. A shorter period where the investment cost can be recovered illustrates that although the investor may wish to await better investment conditions, the lifetime of the field and installation time for each option may not allow for such flexibility. Incorporating these elements into the model framework is likely reduce expected NPV, as well as the additional value of a ROA.

Investment Cost and Technological Uncertainty

The next elements for consideration are the investment costs. Given many previous applications of PFS, we considered there to be little value in waiting to learn more about the development of this cost. The same was not found for the strike price of OW, where there is considerable technological uncertainty related to the feasibility of floating wind farms. This was reflected in the sensitivity of both timing and profitability for various scenarios of the investment cost. Given the technical challenges and lack of cases using OW to electrify platforms, we identify two ways in which RO thinking can be beneficial in handling these challenges. The first considers the development of the Hywind Tampen case. The idea of deterring investment to monitor the outcome of this case rests on an assumptions of that information being available. There are competitive factors to be considered, and although the information exists, it may not be public or easily accessible. On the other hand, the funding through ENOVA was provided with a goal of that case being a test-bed for further developments on the NCS. Working under the assumption that relevant information will be available, we can include the completion of this project as an event. If able to assess characteristics of such an event properly, an estimate of the value of learning the outcome can be made. The firm must then decide whether to investment now, or deter in order to make a more informed decision after the outcome is realized. The second approach considers "learning-by-doing". Dixit and Pindyck (1994) claims there exists information that only becomes available once an option is activated. The uncertainty associated with this information means there is a shadow value in activating the option and learning the reality of either operational difficulties and/or costs. Estimating such a value is of course difficult, but acknowledging that it exists may increase project value and encourage investment where a deterministic NPV approach would reject the option.

Political Uncertainty

Finally, we consider possibilities of including political uncertainty. We identify two areas that may be affected by political changes. Firstly, there are possibilities of reduced taxation levels or public financial support that could reduce costs of projects. Examples of incorporating the effect of various support schemes in a RO setting have previously been applied to wind energy investments in (Boomsma et al., 2012) and (Kitzing et al., 2017). The latter describes attempts at modelling a policy perspective as either being too simplistic, hardly reflecting realistic investment situations or too complicated to apply. An application of similar methods to electrification problem is likely to face these challenges. The purpose of this discussion is not to propose a solution framework that would overcome these barriers, but to emphasize that if such an approach is taken there may be possibilities of capturing the potential value of public support.

Secondly, as the discussion on carbon pricing revealed, this market is heavily influenced by policies and regulatory frameworks. As such, it may not be sufficient to handle uncertain price developments as we would for market prices of electricity or natural gas. Through scenario analysis, we concluded that different degrees of political involvement could affect the carbon price level. The effect of political changes can be viewed as switches, which Dixit and Pindyck (1994) claims can be represented through jump processes. Such processes have previously been applied to investigate the effect on carbon prices due to changes in climate policies in (Blyth et al., 2007) and (Yang et al., 2008). These works handle investments in cases considering power production and focus on the risks arising for changes in climate policies. Such an approach towards developing this thesis can be beneficial for both operating firms and policy makers. For the investors, this could allow them to accurately estimate the risk premium required to activate the option, whilst for policy makers such an approach would illustrate the value of predictability for the industry. Policies could then be tailored to encourage more emission reducing investments.

Inclusion of all suggested improvements would quickly lead to a problem suffering from the curse of dimensionality. Such a problem would be difficult to solve and not aid in making more informed decisions. However, should one of these suggested approaches be followed, it has potential to aid in the decision making process. The finite nature of O&G fields and installation time of the considered options suggests there may be limited flexibility to deter investments. This reduces the benefit of applying RO as opposed to traditional methods relying on deterministic estimates. Despite this, our approach was found to provide additional value to the decision maker, but with potential for improvement. Although stochastic handling of the electricity price was informative, we view the technical uncertainty related to the investment cost of OW and the political uncertainty affecting financial support and carbon prices to have a greater impact. We therefore conclude that the inclusion of these aspects may be needed to maximize the potential of applying a ROA to electrification problems.

8.5 Concluding this Section

This section has presented the results from the BC, evaluated the computational performance and applied sensitivity analysis to a few select parameters. In addition, we have assessed the potential for applying a ROA to this problem and electrification investments in general. Finally, we aim to provide a conclusion for our research questions.

The initial results provided a strong recommendation for investing in electrification using OW. In fact, 98,9% of simulated electricity price trajectories suggested this investment in 2026, with 6,6% of these also suggesting activating the export option beyond 2041. Only 1,1% suggested investment in PFS. With an expected NPV of 1560 mNOK, the recommendation is to activate the OW option in 2026. In the analysis, we have discussed the effect of several conditions that may affect this decision. We therefore aim to summarize this to establish the conditions that have the greatest effect on profitability of electrification investments.

Electricity Price

Interestingly, the cash flows for the dominant OW alternative are independent of the electricity price. Although this could indicate a situation where the development of the electricity price has little effect on profitability, sensitivity analysis for increasing volatility showed otherwise. Specifically, we observed that increased volatility warrants more investments in PFS and increases the expected NPV. We discussed that estimating volatility from historical data may not provide an accurate representation of the future. This can impact the optimal strategy as we found more simulations suggesting PFS than OW for a volatility of $\sigma = 74\%$. Finally, we also found that for high electricity prices beyond the lifetime of the field, the possibility to export power increased the expected NPV. Despite this, the sensitivity analyses throughout this section indicates that factors such as OW cost and carbon price are more determining for the profitability of electrification projects. However, in a more volatile future than for our BC, the impact of the electricity price may be greater.

Natural Gas

The breakdown of the cash flows showed a relatively small contribution of the sale of additional freed gas compared to the cost of electricity and saved carbon charges. For OW-electrification, its contribution to the positive cash flows ranges between 12-15% between 2025 and 2040. The remainder is almost entirely supplied by cost savings in carbon charges and we therefore view developments in the price of natural gas to be less significant to the profitability of the project. Similar to previous discussion on the carbon price, the impact of changes in this market are more likely to impact overall operations than the profitability of the electrification investment. A final point on the freed gas is related to the applied tax rate of 78%. As mentioned in section 7, this may in reality be lower due to tax deductions of investment. In such scenarios, the overall profitability of the electrification investment may be more affected by price changes.

Carbon Price

The breakdown of cash flows revealed savings in carbon costs to be the most significant contributor for both electrification options. Given an expected price increase in the upcoming future, we therefore consider the carbon cost to be the most important factor for the profitability of investments. We observed that price increases led to higher expected NPV, especially if this development happens before 2030. In this regard, we found that active involvement from policy makers was more likely to provide an increased growth rate. Although increased charges generally make the electrification more profitable, we conclude that there is a limit to this relationship. At a certain point, the increase in carbon charges is likely to affect the O&G extraction processes to such an extent that electrification may no longer be an option to be considered.

For market conditions, we therefore conclude that for an electricity price volatility based on historical data, the carbon price is the most determining factor for both profitability and optimal strategy. However, in a more volatile electricity price future, the electricity price may have a larger impact on the optimal strategy.

Investment Costs

For the investment costs, changes to both electrification options were investigated. A 10% and 20% increase were applied for OW, as well reducing the learning rate by half and removing it entirely. The recommended decision did not change, but we observed sensitivity of both investment timing and profitability to changes in OW cost. We therefore concluded that further research on this cost for the case in question may provide better conditions for making the most profitable investment. In conclusion, we attribute the suggested investment timing of 2026 down to two factors. The expected decrease in OW cost in the initial time periods and the expected increase in carbon costs. We therefore advise the operator to monitor developments for both towards 2026.

Finally, we have attempted to establish if the optimal strategy is affected by also including the option to export power to shore beyond the field's lifetime. The initial results of the BC illustrated that additional value could be captured for the highest price realizations of the uncertain process. To estimate this, we restricted the export option to observe the changes in optimal strategy and profitability. Although the suggestions of PFS increased from 1,1% to 10,6%, the recommended choice of option and investment timing remained unchanged. We therefore conclude that including the export option may increase project value, but in the considered case it did not affect the suggested investment decision.

9 Conclusion

This Master's thesis has provided an economical assessment of electrification using PFS or OW. The large infrastructural installations related to electrification raises the issue of how to utilize this beyond the lifetime of the O&G fields. We have therefore investigated whether the optimal strategy is altered by also including the possibility of exporting wind-produced power in a long term perspective. With three available path-dependent options, the objective has been to maximize the expected NPV, by choosing the optimal strategic decisions. By allowing for electricity price uncertainty, we have viewed this investment opportunity in a RO setting and formulated it as a MSIP problem, which has been solved by means of the SDDiP algorithm. To the author's knowledge, this has been the first application of such an approach considering both PFS and OW for electrification.

This setup has been applied to a real life offshore installation, where the operator is currently considering making an investment in electrification. We therefore provide a recommendation of investing in electrification using OW in 2026. Although we do not suggest the export option based on our projection of the future, we advise the operator to monitor developments in the electricity price to activate it under favorable conditions. We summarize the most important findings for the considered case below.

- The initial results provide a strong recommendation for investing in electrification using OW. In fact 98,9% of simulated electricity price suggested this investment in 2026, with 6,6% of these also suggesting investing in the required infrastructure to export power to shore beyond 2040. Only 1,1% suggested investment in PFS to be optimal.
- A 90% confidence interval of the NPV function was estimated to be [1427, 1693] mNOK.
- The deterministic case suggested OW in 2026, which gave a NPV of 1201 mNOK. Thus, based on the mean of the 90% CI, the simulated case gave a 29% increase in expected NPV.
- Although the majority of simulations suggested investing in OW, the required electricity price levels for PFS and EXP|OW were analyzed. The PFS option favored low electricity prices, particularly with a steep price decline in the initial time periods. For EXP|OW, the option was activated for the highest simulated price developments beyond 2040.
- A breakdown of the simulated cash flows revealed the savings in carbon charges to be the most dominant contributor. This was largely due to the expected increase in the carbon price towards 2030.
- We mainly attribute the suggested investment timing of 2026 down to two factors. The expected decrease in OW cost over the initial time periods and the expected increase in carbon costs. We therefore advise the operator to monitor developments for both towards 2026.
- Beside the cost of electricity and CO_2 emissions, the sale of natural gas was shown to contribute to the cash flows. However, we found that a 45% price increase only gave 3% increase in contribution to the positive cash flows. Therefore, changes in the price of natural gas were deemed to have a relatively small impact on the investment decisions.
- We find that a Markov chain with 20 Markov states were sufficient to provide a satisfactory representation of the uncertain electricity process. This was found by using an optimality gap stopping criterion with a specified tolerance of 1%.
- Higher levels of volatility in the electricity price increased the amount of simulations recommending PFS and expected profitability. Per 10% increase in volatility, we observed an average increase of 12% of PFS cases and 11% decrease in OW cases. With a base case volatility of 29%, the first level suggesting PFS to be the optimal choice was found for 74%.
- When restricting the option to export, the decision remained to invest in OW-electrification, but at a loss of profitability. This loss was estimated in the region of [316, 538] mNOK, which showed that the inclusion of the option increased the value of the OW investment option.

Despite this, the inclusion of the export option is not found to affect the recommended decision for this case.

A discussion on project valuation methods showed that there may be significant advantages in taking a ROA to renewable investment decisions. However, although such approaches have been applied to OW investments, an extensive literature review revealed that there have been limited applications within electrification of offshore platforms. Therefore, we have evaluated if elements from RO theory can be beneficial for assessing electrification projects. For our specific case, we find that allowing for an uncertain price process and export in a long term perspective did provide additional value, as opposed to traditional approaches. However, the finite nature of O&G fields and installation time of the considered options means there may be limited flexibility to deter investments in electrification projects. This reduces the potential benefits of applying a ROA. Finally, we have also considered improvements in the RO framework to assess electrification investments. We view the effect of climate change policies to be particularly important, especially with respect to carbon prices. We have therefore referenced literature that have handled such political uncertainty in a RO setting and view this as a potential improvement of the model framework in this thesis. In addition, through sensitivity analysis we found the uncertainty in the cost development of floating OWF to affect both investment timing and profitability. We therefore view active handling of the technical uncertainty related to this immature technology to also provide potential benefits to the decision makers.

With concluding remarks for this study established, our next focus is providing suggestions for further research. In the next section, we will therefore summarize the effect of simplifications made throughout and identify possible extensions and areas of future research.

10 Future Research

In this final section, we provide suggestions for future research. First, we discuss the effect of assumptions and simplifications made in this thesis. This is followed by suggested extensions of the model framework to more accurately capture the real life characteristics of the investment decisions.

10.1 Assumptions and Simplifications

In the previous section, the effect of certain simplifications were discussed. These are repeated and listed below. In addition, we discuss the effect of other assumptions made in the model framework.

- The assumption that the effect on cash flows are immediate leads to a situation where we do not consider the required installation time for each electrification option. As this may take several years, the calculated expected NPV are likely overestimated.
- The estimates of the investment costs of OW are based on the Hywind Tampen case, with an applied learning rate based on floating OW in general. As these are not developed for the case in question, these estimates are likely to reduce the accuracy in our findings.
- We only consider the export option between 2041 and 2050. Had this been extended, it is likely that the threshold for activating the export option would've been lowered as there are more periods available to recover the investment cost.

Another critique, which is similar to the first point, is the handling of the investment cost. Throughout this thesis, we have viewed a ROA as a method that is appropriate for handling the real life complexities of investments. In such a setting, each option has a strike price, which we assumed to be paid in full upon activation of the option. Given the installation time of the infrastructure, this cost is likely to be spread over several years. As such, the sensitivity of the NPV function to the investment timing may be overestimated.

Next, our interest in modelling path-dependencies resulted in assumptions on shared infrastructure. For the export option, our estimates were based on the sum of the electrification options. Therefore, this makes it more challenging to assess the merits of this option itself. The costs related to the option is therefore useful in estimating additional value after previous investments, but less so for only considering the export alternative. In the next subsection, we will present extensions of the model that may capture the characteristics of the export alternative more accurately.

10.2 Extensions

In this subsection, we provide suggestions on how we can extend the research in this thesis. We therefore discuss the effect of correlation between market prices, accounting for emissions, other options that may be available, capacity choices and modifying the constraints for the export option.

Handling Correlation

In this thesis, different prices of CO_2, natural gas and electricity have been applied. However, the correlations between these have not been considered. We briefly discussed the potential impact of increased CO_2 charges on the demand for natural gas, but did not include correlations in the modelling framework. Nor was this accounted for in the applied estimates. We therefore view handling of the correlation between these elements as a potential improvement of the work in this thesis.

Accounting for Emissions

For this case, a 100MW installed capacity is considered for both PFS and OW. Despite this, the applied capacity factor results in 42% more emission reductions for PFS, compared to OW. As such, the PFS option may be considered as the most effective in reducing emissions. However, the discussions around the actual global climate effect from PFS makes it more complex. A more comprehensive evaluation of the potential for reducing GHG emissions may therefore be useful for each option. Although the problem in this thesis has been viewed with an objective of maximizing profitability, the related emission reductions are likely to influence the decision makers.

Alternative Emission Reducing Measures

Works such as (Roussanaly et al., 2019) and (Nguyen et al., 2016) consider electrification options in comparison with other CO_2 mitigating measures. In this paper, we have assessed investment opportunities that aims to reduce emissions, but there may also be other options available to the decision makers. These can range from efficiency improvements, hydrogen production, carbon capture and storage or other OW solutions. Possible investment opportunities within these areas are therefore likely to be relevant. An interesting extension of the model is therefore the inclusion of other emission reducing options, as this might provide a more accurate reflection of the actual situation for the investing firm.

Capacity Choices

An element often found in models for investment opportunities, especially within RO, is allowing for timing and capacity choices. In this thesis, we have considered the optimal investment timing, given a set power capacity for each option. Such a setup can potentially ignore possibilities of obtaining the most energy efficient solutions and other real life characteristics of the problem. The decrease in power demand to 75MW beyond 2033 was accounted for by both the OW and PFS alternatives. In reality, this decrease will happen more gradually depending on the amount of exported gas. More accurate handling of the offshore power processes brings us into a realm of assessing the optimal operations in terms of GT efficiency and stability in transmissions. A balance must therefore be struck here, as the main objective will still be from an economical perspective. However, including capacity choices may provide a better representation of the real offshore situation.

Removing Constraints for the Export Option

Finally, this thesis restricted the export option until the end of the field's lifetime. Although we observed additional value from this setup, this constraint may have hindered an evaluation of the full potential of such an option. We opted for this solution, as introducing export of power when there remains power producing processes offshore was not deemed a realistic setup. Instead, a more interesting situation is modelling the transition from offshore O&G production into power export using OW. In such a setting, the profitability of the platform must be weighted against the benefits of initiating an export project. In this thesis, we have discussed that changes in carbon and natural gas prices may have larger impacts on overall operations, than for the decision to electrify. In this proposed setup, we would need to consider the impact of both these prices when deciding on the optimal timing of such a transition.

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Appendix

A More Details on Choice of Power duty

In this appendix section, we provide further details on the power duty, the gas turbines(GT) and the amount of fuel saved by electrifying.

Power Duty

As has been mentioned in the Case Study section, see 7, the investigated power duties are not constant. At the platform we have 5 GT, who have different purposes and can supply between 18-25 MW annually. Of these, three can be replaced. In addition, by including the subsea compressor's (SSC) power supply in this solution we have an additional power demand of 24-28 MW.

In total we then have a power demand between 114-153MW, with 78-103MW that may be replaced. Beyond 2033, we subtract 18-25MW from this number as one less GT is available for export. We therefore choose a value of 100MW before 2033 and 75MW after in the calculations.

Freed Gas

Furthermore, this affects the additional amount of gas available for export and therefore saved emission charges. The operator has provided information that 3 % of the exported gas is used at present to fuel the GT. With 27 Sm^3 daily, this corresponds to 0,84 Sm^3 over the 5 GT. I.e. 0,168 Sm^3 for each. It is here important to note the assumption that the fuel consumption is constant per MW produced. I.e. we assume constant efficiency. This gives 0,336 Sm^3 for 2 GT and 0,504 Sm^3 for 3 GT. To also include the SSC compressor here, we linearize the relationship based on power demand according to the following relationship

$$Gas^{SSC} = \frac{Power^{SSC}}{Power^{GT}} Gas^{GT} \tag{26}$$

$$Gas^{SSC} = \frac{24MW}{20MW} 0,168Sm^3 = 0,202Sm^3 \tag{27}$$

By electrifying, we then get for replacing 3 GT and a SSC(100MW):

Freed Gas: 0,706 Sm^3 of natural gas

For 2 GT and a SSC (75MW):

Freed Gas: 0,538 Sm^3 of natural gas

These values are then used to calculate additional revenue generated from additional sale of gas, as well as saved CO_2 and NOx charges.

B Breakdown of Investment Costs

This section aims to provide more insight into the available data and the assumptions made to estimate the investment cost and cost reductions from the inter-dependency between considered options. All prices are given in 2021-level. The initial investment costs for PFS and OW for electrification are given as:

PFS: 8,5 bNOK plus an additional 1,5 bNOK for integrating the SSC. The 1,5 bNOK are relevant until 2030, while the 8,5 bNOK is held constant until the option expires in 2040.

OW-electrification: 5,68 in 2021, but set to decrease until 2040 (when option expires).

If no electrification has occurred until 2030, a cost of 3,5 bNOK will happen to change the power supply of the SSC. Thus, after 2030 the PFS cost decreases to the 8,5 bNOK.

In table 11 in section 7.2.1 we established the shared infrastructure between each option. For PFS and OW electrification cases, there is a shared infrastructure in the offshore control hub. Estimating the value of this control hub is challenging, but based on input from the operator and public assessments reports an estimate has been made. We are given from the operator that 60 % of the investment cost for PFS is related to the cables and the preparation of pathway. In the assessment of the Hywind Tampen project, an alternative cost of a PFS solution was also investigated, with an overview of the CAPEX distributions for that case[10]. Here, planning costs were set at 7 %, while the onshore substation set at 16 % of the CAPEX (Equinor, 2019). Thus, we have a rough estimate of 18 % [100-60-16-7]% of CAPEX for offshore control hub. However, to allow for contingencies and to be conservative in our estimates, we apply a 15 %. For a 100MW PFS and OW for electrification solution we then have a shared cost of 0,15*8,5bNOK, which equals 1,275 bNOK.

Next we turn to the cost of exporting OW produced power to shore beyond the field's lifetime. Based on our assumptions of shared infrastructure, the total export cost then becomes the sum of the PFS investment and OW-electrification, net the cost of the offshore control hub.

Export cost: 8,5 bNOK + 5,68 bNOK - 1,275 bNOK = 12,905 bNOK,

which is set to decrease as floating OW cost decreases.

Now that we have established the cost of each option alone and the shared cost between the electrification options, we shift our focus to the potential cost reductions for OW export given previous investments.

Export cost given PFS

Given shared infrastructure, the export cost could be estimated as export cost net of PFS cost(12,905 bNOK - 8,5 bNOK = 4,405) bNOK. However, although the cable pathways and cables are needed, we must incur a cost for modifying the setup. This cost includes planning costs and the actual changes needed to allow power to be transmitted in the opposite direction. In this thesis, we acknowledge that this cost is difficult to estimate. We apply a cost of 1bNOK, but this will be varied to investigate it's effect on results. We therefore have an investment cost of 5,405 bNOK to export power given PFS infrastructure is in place.

Export given OW

Here, we have a shared infrastructure of offshore control hub and the OW turbines themselves. As these were set at 5,68 bNOK in 2021, the investment cost is related to the investment required to install cables and onshore power station. This is estimated to be the PFS cost (8,5 bNOK) net of the offshore control hub (1,275 bNOK) = 7,225 bNOK. Again, we incur a modification cost to change the OW-electrification setup to instead be set for power export. The same situation with uncertainties holds for this case. We therefore estimate this at 0,5 bNOK, but will investigate the effect of increasing it. Thus, the strike for export given OW is set at 7,725 bNOK.

Export given both PFS and OW

[10] Page 35 of 108. Breakdown of CAPEX in table 2-5 for alternative 1

Export after both PFS and OW would mean all the required infrastructure would be in place. We do not set this at zero, as there are modification costs to be considered. Thus, this cost is set as the sum of these, meaning 1,5 bNOK.

C Price Data

This appendix section will provide lists of price estimates used in the calculations.

Figure 24 shows the price estimates used for natural gas in the computational study.

Rystad estimates for natural gas price. Three scenarios in units [NOK/Sm^3]

Year	Low	Medium	High
2021	1,97	1,97	1,97
2022	1,98	2	2,02
2023	1,99	2,03	2,07
2024	2	2,06	2,12
2025	2,01	2,09	2,17
2026	2,02	2,12	2,22
2027	2,03	2,15	2,27
2028	2,04	2,18	2,32
2029	2,05	2,21	2,37
2030	2,06	2,24	2,42
2031	2,07	2,27	2,47
2032	2,08	2,3	2,52
2033	2,09	2,33	2,57
2034	2,1	2,36	2,62
2035	2,11	2,39	2,67
2036	2,12	2,42	2,72
2037	2,13	2,46	2,78
2038	2,15	2,5	2,84
2039	2,17	2,54	2,9
2040	2,19	2,58	2,96

Figure 24: Three scenarios of natural gas price until 2040. Based on (Rystad Energy, 2020).

Next is a figure showing data used for carbon price levels used in calculations.

2000-level	Continuous Growth	High Growth	Directed Transition	Gradual Development	Societal commitment	Techno-Friendly
700	700	700	700	700	700	700
845	845	845	715	700	700	700
990	990	990	1130	700	700	700
1135	1135	1135	1545	700	700	700
1280	1280	1280	1960	830	700	700
1425	1425	1425	2282	920	770	700
1570	1570	1570	2604	1010	920	700
1715	1715	1715	2926	1100	1070	754
1860	1860	1860	3248	1190	1220	862
2000	2000	2000	3570	1280	1370	970
2000	2150	2200	3876	1390	1642	1162
2000	2300	2400	4182	1500	1914	1354
2000	2450	2600	4488	1610	2186	1546
2000	2600	2800	4794	1720	2458	1738
2000	2750	3000	5100	1830	2730	1930
2000	2900	3200	5440	1986	3178	2246
2000	3050	3400	5780	2142	3626	2562
2000	3200	3600	6120	2298	4074	2878
2000	3350	3800	6460	2454	4522	3194
2000	3500	4000	6800	2610	4970	3510
2000	3650	4200	7140	2784	5634	3978
2000	3800	4400	7480	2958	6298	4446
2000	3950	4600	7820	3132	6962	4914
2000	4100	4800	8160	3306	7626	5382
2000	4250	5000	8500	3480	8290	5850
2000	4400	5200	8800	3654	9182	6480
2000	4550	5400	9100	3828	10074	7110
2000	4700	5600	9400	4002	10966	7740
2000	4850	5800	9700	4176	11858	8370
2000	5000	6000	10000	4350	12750	9000

Figure 25: Annual carbon price data used in calculations. Units of [NOK/ton CO2]

D Inter-Dependency Constraints

In this appendix section, we elaborate on the constraints used for handling the equivalences formulated for the continuous variables.

Export power if no previous decision has been made

For this situation the following relationship must hold

$$\{x_t^{EXP} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 0\} \tag{28}$$

, where we include both t and t-1 terms to ensure that the investment cost only happens once.

First, we must modify this relationship so that it can be represented by modelling constraints. We start by turning equivalences into opposite implications. The first implication is given as

$$\{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 0\} \implies \{x_t^{EXP} = 1\} \tag{29}$$

, which can be represented by the following restriction

$$(1 - z_t^{EXP}) + z_{t-1}^{EXP} + z_t^{OW} + z_t^{PFS} + x_t^{EXP} \geq 1 \tag{30}$$

The second implication is

$$\{x_t^{EXP} = 1\} \implies \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 0\} \tag{31}$$

Here, we have four conditions on the right hand side, and we therefore need to represent this using the following four constraints.

$$(1 - x_t^{EXP}) + z_t^{EXP} \geq 1 \tag{32}$$

$$x_t^{EXP} + z_{t-1}^{EXP} \leq 1 \tag{33}$$

$$x_t^{EXP} + z_t^{OW} \leq 1 \tag{34}$$

$$x_t^{EXP} + z_t^{PFS} \leq 1 \tag{35}$$

Export power if OW electrification investment has been done previously

Here, we follow the same procedure as above with the following relationship

$$\{x_t^{EXP-OW} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 0\} \tag{36}$$

The first implication is given as

$$\{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 0\} \implies \{x_t^{EXP-OW} = 1\} \tag{37}$$

, which can be represented by the following restriction

$$(1 - z_t^{EXP}) + z_{t-1}^{EXP} + (1 - z_t^{OW}) + z_t^{PFS} + x_t^{EXP-OW} \geq 1 \tag{38}$$

The second implication is

$$\{x_t^{EXP} = 1\} \implies \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 0\} \tag{39}$$

, which can be represented by the three following restrictions

$$(1 - x_t^{EXP-OW}) + z_t^{EXP} \geq 1 \tag{40}$$

$$x_t^{EXP-OW} + z_{t-1}^{EXP} \leq 1 \tag{41}$$

$$(1 - x_t^{EXP-OW}) + z_t^{OW} \geq 1 \tag{42}$$

$$x_t^{EXP-OW} + z_t^{PFS} \leq 1 \tag{43}$$

Export power if PFS investment has been done previously

Here, we follow the same procedure as above with the following relationship

$$\{x_t^{EXP-PFS} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \tag{44}$$

The first implication is given as

$$\{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \implies \{x_t^{EXP-PFS} = 1\} \tag{45}$$

, which can be represented by the following restriction

$$(1 - z_t^{EXP}) + z_{t-1}^{EXP} + z_t^{OW} + (1 - z_t^{PFS}) + x_t^{EXP-PFS} \geq 1 \tag{46}$$

The second implication is

$$\{x_t^{EXP-PFS} = 1\} \implies \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \tag{47}$$

, which can be represented by the three following restrictions

$$(1 - x_t^{EXP-PFS}) + z_t^{EXP} \geq 1 \tag{48}$$

$$x_t^{EXP-PFS} + z_{t-1}^{EXP} \leq 1 \tag{49}$$

$$x_t^{EXP-PFS} + z_t^{OW} \leq 1 \tag{50}$$

$$(1 - x_t^{EXP-PFS}) + z_t^{PFS} \geq 1 \tag{51}$$

Invest in power export after both OW and PFS has been done

Here, we follow the same procedure as above with the following relationship

$$\{x_t^{EXP-PFS+OW} = 1\} \iff \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \tag{52}$$

The first implication is given as

$$\{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \implies \{x_t^{EXP-PFS+OW} = 1\} \tag{53}$$

, which can be represented by the following restriction

$$(1 - z_t^{EXP}) + z_{t-1} + (1 - z_t^{OW}) + (1 - z_t^{PFS}) + x_t^{EXP-PFS+OW} \geq 1 \tag{54}$$

The second implication is

$$\{x_t^{EXP-PFS+OW} = 1\} \implies \{z_t^{EXP} = 1\} \wedge \{z_{t-1}^{EXP} = 0\} \wedge \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \tag{55}$$

, which can be represented by the three following restrictions

$$(1 - x_t^{EXP-PFS+OW}) + z_t^{EXP} \geq 1 \tag{56}$$

$$x_t^{EXP-PFS+OW} + z_{t-1}^{EXP} \leq 1 \tag{57}$$

$$(1 - x_t^{EXP-PFS+OW}) + z_t^{OW} \geq 1 \tag{58}$$

$$(1 - x_t^{EXP-PFS+OW}) + z_t^{PFS} \geq 1 \tag{59}$$

Invest in OW given PFS has been done previously

The above-mentioned path dependencies cause changes in the investment costs, while the revenue streams and operational expenditures are still related to the three main binary decision variables. This is not the case for a path dependency between PFS and OW for electrification as these two cannot electrify more than the actual offshore power demand. To model this, we introduce two new continuous variables, $x_t^OW - PFS - 1$ and $x_t^OW - PFS - 2$, which handle investment cost and changes in annual CF respectively. This is required to ensure that the investment cost only happens once, while the cash flows are included for several years.

$$\{x_t^{OW-PFS-1} = 1\} \iff \{z_t^{OW} = 1\} \wedge \{z_{t-1}^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \tag{60}$$

First implication is

$$\{z_t^{OW} = 1\} \wedge \{z_{t-1}^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \implies \{x_t^{OW-PFS-1} = 1\} \tag{61}$$

, with restrictions of

$$(1 - z_t^{OW}) + z_{t-1}^{OW} + (1 - z_t^{PFS}) + z_t^{EXP} + x_t^{OW-PFS-1} \geq 1 \tag{62}$$

and the other implication is

$$\{x_t^{OW-PFS-1} = 1\} \implies \{z_t^{OW} = 1\} \wedge \{z_{t-1}^{OW} = 0\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \tag{63}$$

, with restrictions

$$(1 - x_t^{OW-PFS-1}) + z_t^{OW} \geq 1 \tag{64}$$

$$x_t^{OW-PFS-1} + z_{t-1}^{OW} \leq 1 \tag{65}$$

$$(1 - x_t^{OW-PFS-1}) + z_t^{PFS} \geq 1 \tag{66}$$

$$x_t^{OW-PFS-1} + z_t^{EXP} \leq 1 \tag{67}$$

The situation for the cash flow is very similar, with the exception that we do not require the past value of z_t^{OW} to be zero.

Thus, we have for cash flows and $x_t^{OW-PFS-2}$ the following relationship

$$\{x_t^{OW-PFS-2} = 1\} \iff \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \tag{68}$$

, with first implication

$$\{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \implies \{x_t^{OW-PFS-2} = 1\} \tag{69}$$

and restriction

$$(1 - z_t^{OW}) + (1 - z_t^{PFS}) + z_t^{EXP} + x_t^{OW-PFS-2} \geq 1 \tag{70}$$

and the other implication is

$$\{x_t^{OW-PFS-2} = 1\} \implies \{z_t^{OW} = 1\} \wedge \{z_t^{PFS} = 1\} \wedge \{z_t^{EXP} = 0\} \tag{71}$$

, with restrictions

$$(1 - x_t^{OW-PFS-2}) + z_t^{OW} \geq 1 \tag{72}$$

$$(1 - x_t^{OW-PFS-2}) + z_t^{PFS} \geq 1 \tag{73}$$

$$x_t^{OW-PFS-2} + z_t^{EXP} \leq 1 \tag{74}$$