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Electrifying the Norwegian Continental Shelf

A Financial Comparison of Small Modular Reactors and Floating Offshore Wind for Oil and Gas Installations

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Abstract

The purpose of this thesis is to evaluate why and how electrification of the Norwegian continental shelf should be undertaken, focusing on two potential alternative energy sources: small modular reactors (SMRs) and floating offshore wind (FOW). This study explores the feasibility and financial viability of these technologies within the context of electrifying oil and gas installations.

The thesis is structured into three main sections. The first provides an overview of the technologies, their markets, and their relevance to electrification efforts. The second examines the broader markets for electricity and oil and gas, framing the context for energy transition on the continental shelf. Finally, a detailed financial analysis is presented, incorporating key input assumptions and findings.

The financial analysis indicates that both SMRs and FOW are financially viable options for electrification. Investment analyses reveal positive and comparable net present value figures for both technologies, with levelized cost of electricity estimates of approximately NOK 1,203/MWh for SMRs and NOK 1,503/MWh for FOW. While SMRs exhibit advantages in terms of safety and emissions reduction, FOW performs better in terms of land use and spatial requirements.

Despite their financial viability in this specific context, broader application of SMRs and FOW in Norway's general energy mix requires further analysis. The findings highlight the importance of accounting for revenues from gas sales and carbon tax savings, as these factors are unique to the oil and gas context. The analysis underscores that both technologies, while promising, should be evaluated more comprehensively before being considered for large-scale implementation in Norway's energy sector. This thesis contributes to the ongoing discussion of Norway's energy transition by providing a nuanced comparison of SMRs and FOW in the context of electrifying the Norwegian continental shelf.

Abbreviations

BFOW	Bottom-fixed Offshore Wind
CAPEX	Capital Expenditure
FOW	Floating Offshore Wind
FOWF	Floating Offshore Wind Farm
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LCOE	Levelized Cost Of Energy
NPV	Net Present Value
OPEX	Operational Expenditure
OW	Offshore Wind
PPA	Power Purchase Agreement
SMR	Small Modular Reactor
WACC	Weighted Average Cost of Capital

Applied exchangerates[1]

EUR/NOK	11.63
USD/NOK	10.70
GBP/NOK	13.65
SEK/NOK	1.02

[1] The applied exchange rates are the LTM average retrieved from Bloomberg.

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1. Introduction

Ekofisk, discovered on December 23, 1969, is the first major offshore oil field on the Norwegian continental shelf and has since become one of the most productive and profitable fields world-wide (Regjeringen, 2021). This discovery marked the beginning of Norway's oil era, leading to the identification of numerous other fields in subsequent years. Today, the petroleum industry stands as the largest source of revenue for the country, making activity on the Norwegian continental shelf a key driver of the national economy.

However, the economic growth and prosperity brought by the Norwegian oil industry has come at a cost. Human activity is widely acknowledged as the primary driver of global warming and the rising CO_2 levels. It is crucial to lower greenhouse gas emissions to reduce the impact of climate change, of which the energy sector is the largest contributor. The energy sector is responsible for approximately 75% of global emissions, with 3.5 billion people living in contexts likely to be highly vulnerable to climate change (UNDP, 2024). Globally, emissions from oil and gas operations are estimated to account for around 15% of all energy-related emissions (IEA, 2023). In Norway, this figure is even higher, contributing 25% of the country's total emissions (Statistisk Sentralbyrå, 2024).

The latest report from the UN Environment Programme states that we are currently on the trajectory for a 3-degree global temperature increase by 2100 (UNDP, 2024). This significantly exceeds the 1.5-degree limit set by the Paris Agreement and is considered a level of global warming that the world cannot withstand. Norway is a signatory to this agreement and has pledged to reduce its emissions from 49 million tons of CO_2 to 23 million tons by 2030. This represents a 55% reduction compared to 1990 levels and will require substantial changes in Norway's energy production (Trædal, u.d.).

Two-thirds of the measures identified to achieve the Norwegian 2030 target requires some form of electrification, with 20% specifically related to electrifying the oil and gas industry (Thema, 2023). There are currently several alternatives available for electrifying the sector, each differing in terms of cost, land use, variability, and safety. Some alternative technologies considered include offshore and onshore wind, solar power, expansions of current hydro power plants, carbon capture and nuclear reactors. The window for investment decisions is narrowing quickly, and the government needs comprehensive studies of the available technologies to initiate construction as soon as possible. To sustain the Norwegian oil and gas industry, while simultaneously meeting global and national climate targets for both 2030 and 2050, it is imperative to electrify oil and gas installations with significant remaining lifespans.

Despite being one of the world's largest exporters of oil and gas, Norway uses only a small portion of its extracted resources domestically. This is primarily due to the country's reliance on hydropower, which has long been a cornerstone of Norwegian energy policy. The government's commitment to developing hydroelectric capacity has positioned Norway as a leader in renewable energy consumption. As of 2022, an estimated 98% of the country's power consumption was derived from renewable sources, with hydropower alone accounting for 89% (IEA, 2024).

However, some would argue that this strong focus on hydropower has led to underinvestment in other forms of alternative energy, particularly nuclear energy. Despite Norway's active role in nuclear research in the post-war era, the country never pursued the development of a commercial nuclear power industry. This decision was influenced by several factors, including long construction timelines, high costs, and public concerns over the perceived risks associated with nuclear energy. Unlike other alternative sources, nuclear power can provide a stable and continuous electricity supply, unaffected by variable weather conditions like sunshine, wind, or rainfall. This makes it an attractive option for electrification of energy-intensive industries, such as oil and gas.

Another promising, yet underdeveloped, alternative technology in the Norwegian context is floating offshore wind. While the technology for bottom-fixed offshore wind has advanced further, much of the North Sea is too deep for such installations. As a result, floating offshore wind emerges as the only viable wind power alternative for electrifying the remaining installations on the continental shelf. Although less mature than nuclear power, the potential for floating wind energy is promising. The main challenge lies in its current high costs, due to the relatively unproven nature of the technology. Despite this, the Norwegian government is preparing to make significant investments, recognizing its potential to diversify the country's energy mix and achieve stated climate targets. Given these considerations, a thorough evaluation of nuclear power and offshore floating wind is essential to guide informed investment decisions. This thesis aims to present an investment and cost analysis for the potential electrification of oil and gas installations to contribute to the broader discussion on the topic.

1.1 Research question

The purpose of this master's thesis is to assess the cost savings and potential revenues associated with electrifying oil and gas installations in Norway using nuclear power, specifically small modular reactors, and floating offshore wind. Furthermore, the thesis evaluates the various cost components of each technology, drawing on relevant literature, as well as data gathered through interviews and discussions with industry experts. To the best of our knowledge, few comprehensive financial analyses have examined these specific technologies and their potential for electrifying the oil and gas sector, particularly in a Norwegian context. Therefore, the purpose of this thesis is to provide a thorough assessment of:

Are Small Modular Reactors or Floating Offshore Wind financially viable alternatives for electrifying oil and gas installations on the Norwegian continental shelf?

The debate surrounding the electrification of the Norwegian continental shelf is both active and highly polarized. Discussions are shaped by differing perspectives among individuals, organizations, and the government, leading to significant variation in cost estimates and projections for various technologies. Given the significant impact on the public and regional development, it is essential to thoroughly evaluate all viable options to ensure informed decision-making. Through this thesis, we aim to provide new insights and contribute constructively to the ongoing discussion about the future of energy production on the Norwegian continental shelf.

The following sections provide an overview of the current markets and technologies for both nuclear SMRs and FOW. Sections 3 and 4 outline the power market and the oil and gas market, respectively. Section 5 examines the rationale for and implementation of electrification. A brief theoretical review follows, covering relevant financial concepts used in the data and investment analyses. Following the theoretical review, the data and investment case chapters are presented. Finally, Sections 10 and 11 present a discussion of the results and the conclusion.

2. Nuclear power

Since nuclear power began commercial operations in 1951, it has primarily depended on large-scale reactors for electricity generation. In recent years, SMRs have emerged as an innovative alternative. These smaller reactors retain the benefits of traditional nuclear technology while introducing improved safety, modularity, and flexibility in deployment. This section examines the Nordic nuclear power market, the general technology, and the advancements in SMRs.

2.1 Nuclear power in a Norwegian context

Norway currently has no operational nuclear reactors or power plants. However, the country has a notable historical association with nuclear technology. Over the years, Norway has operated four research-oriented nuclear reactors, including JEEP I (1951–1967) and JEEP II (1966–2019) (DSA, 2021). These reactors played a crucial role in advancing scientific research in fundamental physics and nuclear safety.

During the 1960s and 1970s, Norway engaged in extensive exploration of nuclear energy's potential. In 1969, parliamentary approval was granted for nuclear power planning, and by 1974, a proposal to construct a nuclear plant in the Oslofjord region was under consideration (Nikel, 2021). However, the 1979 Three Mile Island accident significantly shaped Norway's energy policies, resulting in a strategic preference for hydropower over nuclear energy (Nikel, 2021).

In recent years, the discussion around nuclear energy has gained renewed attention, with 56% of Norwegians under 30 expressing a favorable attitude toward its adoption (Ipsos, 2023). According to Ipsos, nuclear energy is now the preferred energy source in Norway, garnering 29% support compared to 25% for hydropower (Ipsos, 2023). While the current Prime Minister, Jonas Gahr Støre, acknowledges the inevitability of nuclear power as a component of the global energy mix, he remains cautious about its applicability within the Norwegian context (Bogen, 2024). Nonetheless, interest in nuclear energy is gaining traction among Norwegian municipalities, with 50 local governments expressing a positive stance toward the technology. Among these, three municipalities, Aure, Heim, and Narvik, have taken additional steps by actively exploring the potential for deploying SMRs as a sustainable energy solution (Bogen, 2024).

2.2 Nordic scope

In the Nordic region, Finland and Sweden are the only countries currently utilizing nuclear energy on a commercial scale. Denmark, historically opposed to nuclear power, has seen a shift in public opinion in recent years, mirroring trends observed in Norway.

Despite a 1980 policy decision to phase out nuclear power, Sweden has continued to rely on nuclear energy as a significant part of its electricity generation. Today, Sweden operates six nuclear reactors, located at Forsmark, Ringhals, and Oskarshamn (WNA, 2024). Together, these facilities contribute approximately 30% of Sweden's electricity, equivalent to 51.9 TWh annually, with production over the past five years averaging 61.3 TWh (WNA, 2024).

In June 2023, Sweden set an ambitious goal to achieve 100% fossil-free electricity by 2040 (Carlen, et al., 2024). Building on this commitment, the Swedish government announced in November 2023 plans to construct two new large-scale nuclear reactors by 2035. Additionally, the government outlined a broader vision to expand the nuclear energy portfolio by 2045, including 10 new reactors, with a focus on incorporating SMRs (Carlen, et al., 2024).

Finland has similarly embraced nuclear power as a cornerstone of its electricity production, with nuclear energy accounting for 41% of the country's electricity output in 2023 (WNA, 2024). The nation's nuclear infrastructure includes two primary facilities. The Loviisa Nuclear Power Plant, operated by Fortum, houses two reactors, while the Olkiluoto Nuclear Power Plant operates three reactors. A notable milestone in Finnish nuclear energy was achieved in 2023 when Olkiluoto's third reactor, with a capacity of 1,600 MW, became operational, making it one of the largest nuclear reactors in Europe. Together, Finland's nuclear facilities produce over 30 TWh annually, with a total installed capacity of 4,400 MW (WNA, 2024).

Finland's energy policy aims to achieve carbon neutrality by 2035, which includes phasing out coal power by May 2029. To support this transition, the government plans to commission two new nuclear reactors and extend the operational lifespans of existing ones. However, not all projects have progressed smoothly. The planned Hanhikivi Nuclear Power Plant, intended to provide 10% of Finland's energy needs, was canceled in May 2022 due to delays and geopolitical concerns arising from its reliance on Russian involvement after Russia's invasion of Ukraine (WNA, 2024).

From a broader perspective, the Nordic region contributes modestly to European and global nuclear power generation. Figures 2.1 and 2.2 illustrate the current distribution.

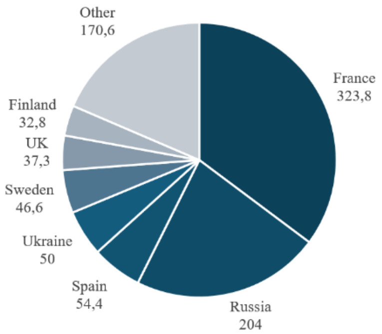

Figure 2.1: *Nuclear power production by European countries, billion KWh, data from World Nuclear Association (2024)*

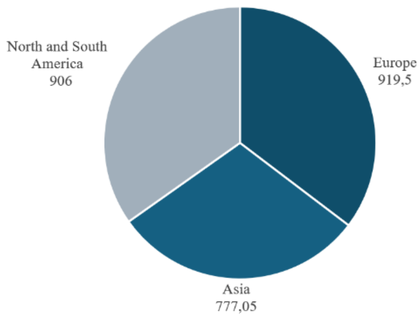

Figure 2.2: *Nuclear power production by continent, billion KWh, data from World Nuclear Association (2024)*

2.3 Technology

Nuclear power production is recognized for its ability to generate immense amounts of energy with minimal carbon emissions through nuclear fission (EIA, 2023). Nuclear fission occurs when a neutron collides with a larger atom, typically uranium-235, causing it to split into two smaller atoms (EIA, 2023). This process releases a huge amount of energy in the form of heat. Along with the heat, additional neutrons are released, which collides with other uranium atoms, triggering a chain reaction. This continuous release of energy from the chain reaction is used to heat water and produce steam. The steam is then used to spin large turbines which in turn drives a generator to produce electricity. A nuclear power plant consists of three main parts: the reactor, the turbine-generator system, and supporting infrastructure, including secondary systems (Rystad Energy, 2023).

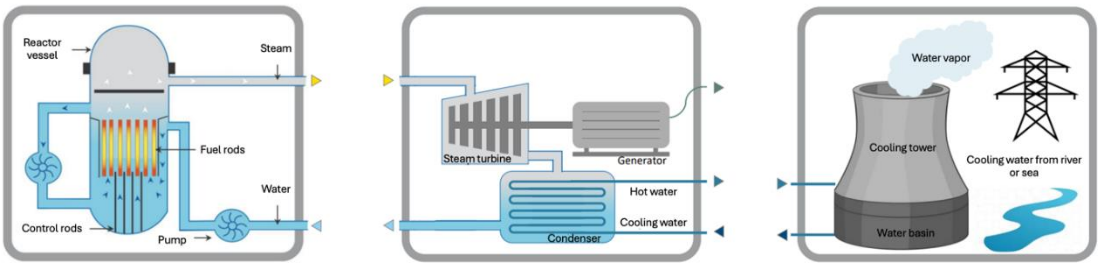

Figure 2.1: *Simplified structure of a nuclear power plant with a PWR. Source: Rystad (2023)*

Nuclear fission occurs in the reactor. The most common reactors type is Light Water Reactors (LWRs), Heavy Water Reactors (HWRs), and Gas-Cooled Reactors (GCRs) (Rystad Energy, 2023). LWRs are categorized into Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). PWRs operate by maintaining water under high pressure to prevent it from boiling within the reactor core. In contrast, BWRs allow water to boil directly in the core to produce steam. Sweden currently operates two PWRs and four BWRs, while Finland has three PWRs and two BWRs. Finland's newest reactor, which began operation in 2023, is a PWR.

HWRs, on the other hand, use heavy water as a coolant, which allows the use of natural uranium fuel. Although this approach eliminates the need for enriched uranium, the cost of heavy water is significantly higher (Rystad Energy, 2023). Lastly, GCRs rely on gas as a coolant. Advanced Gas-Cooled Reactors (AGR) utilize carbon dioxide, while High-Temperature Gas-Cooled Reactors (HTGR) employ helium for cooling. Each type offers unique advantages depending on the specific energy production requirements.

Following the fission, the turbine-generator system converts thermal energy from the reactor into electricity. Steam from the reactor drives the turbines, which in turn power generators to produce electrical energy. Once the steam condenses back into water, it is recirculated to the reactor to repeat the cycle. Lastly, waste management systems handle radioactive waste, ensuring safe disposal. Most reactors also use a cooling system to remove excess heat generated during the fission process, ensuring that the reactor core remains at a safe temperature and preventing overheating or potential meltdowns**.** Power plants located near natural water sources, such as rivers or oceans, can utilize these bodies of water for heat dissipation instead of relying on cooling towers (Rystad Energy, 2023).

2.3.1 Fuel

Uranium is the most widely used energy source for nuclear power plants. Once uranium is mined, the isotope U-235 must be extracted and processed before it can be used as fuel. The nucleus of U-235 contains immense energy stored in the bonds that hold it together, which is released when these bonds break during nuclear fission (EIA, 2023). To illustrate its potency, a single uranium pellet, about one inch in size, produces the same amount of energy as 120 gallons of oil, 17,000 cubic feet of natural gas, or one ton of coal (Bhutada, 2021). Large uranium deposits are found globally, with about two-thirds of the world's uranium production coming from Kazakhstan, Canada, and Australia, while Namibia and Russia are also significant producers (WNA, 2024).

Despite the availability of vast amounts of U-235, uranium is considered a non-renewable energy source (EIA, 2023). This classification stems from the fact that uranium is finite and cannot replenish itself on a human timescale. However, nuclear energy's role in decarbonization complicates its categorization. While it is not renewable, it produces significant amounts of low-carbon electricity. This complexity is reflected in policy updates like Sweden's June 2023 shift from targeting “100% renewable electricity by 2040” to “100% fossil-free electricity” (Carlen, et al., 2024). By emphasizing fossil-free energy rather than strictly renewable sources, Sweden demonstrates a greater willingness to produce nuclear energy, challenging traditional energy classifications in the process.

2.3.2 Small modular reactors

Since the 1940s, nuclear power has undergone continuous development. In the early years, between 1940 and 1950, reactors were primarily experimental, used for research, weapons material production, and early electricity generation. This was followed by the development of Generation II reactors, the majority of which are still in operation today. Starting in the 1990s, Generation III reactors were introduced, building upon the advancements of Generation II with significantly enhanced fuel technology, and safety measures. It is within the framework of Generation III that SMRs has emerged as a key innovation, representing the latest advancement in nuclear technology (Rystad Energy, 2023).

SMRs are compact nuclear reactors with an electrical capacity up to 470 MW (European Commission, 2023). In contrast, Generation II and large-scale nuclear power plants generate over 1,000 MW. Although SMRs produce less energy, they offer several distinct advantages due to their advanced design. First, as the name suggests, SMRs are smaller in size, requiring less space and cooling water, making them more flexible in terms of site selection compared to larger plants. Second, their modular nature allows them to be mass-produced, resulting in cost savings through economies of scale. Third, SMR systems and components can be pre-assembled in factories and transported as modules or fully built units, reducing installation costs. Additionally, their smaller size and capacity make them ideal for deployment in rural areas, where they can supply clean, reliable energy to smaller towns or industries without the need for costly upgrades to the power grid (European Commission, 2023).

Norsk Kjernekraft AS (NKK), an energy company specializing in nuclear power in Norway, has identified four SMR reactor technologies with the highest potential for success in the country. The selected technologies shown in the table below were ranked based on several key characteristics[2]. Among these, BWRX-300 is considered slightly more promising for implementation in Norway, though all four remain relevant.

Reactor	Output MW	Construction, mo.	Types	Conutry	Status
BWRX-300	300	26	BWR	USA and Japan	Detailed Design
Rolls-Royce SMR	470	24	PWR	UK	Detailed Design
SMR-160	160	39	PWR	USA	Preliminary Design Completed
VOYGR	5/6/12 X 77	36	PWR	USA	Equipment Manufacturing in progress

Table 2.1: *Comparison of selected SMR technologies, input from NKK (2024)*

2.4 Capacity factor

Defined by Letcher (2017), capacity factor is the percentage of actual energy produced relative to the theoretical maximum. The calculation involves dividing the actual annual energy production of a turbine by the maximum possible energy production, multiplied by the total hours in a year.

$$Capacity\ factor = \frac{E_{actual}}{E_{ideal}} = \frac{Time * \bar{P}}{Time * P_N} = \frac{Annual\ Energy\ Production_{actual}}{Time * P_N}$$

The capacity factor of nuclear reactors has steadily increased over time. In 2023, the global average capacity factor reached 81.5%, up from 65% in 1970 (WNA, 2024). According to International Atomic Energy Agency, a significant portion of the reactors worldwide today operate with a capacity factor exceeding 90% (IAEA, 2024). However, Eastern Europe and Russia has experienced a decline from an average capacity factor of 83% during 2018-2022 to 77% in 2023. In contrast, Western and Central Europe reported an increase from 67 to 73% over the same period (WNA, 2024).

Capacity factors vary by reactor type. According to the World Nuclear Association, BWRs achieved the highest capacity factor in 2023 at 90%. In the United States, LWRs demonstrated even higher performance. The U.S. Energy Information Administration (EIA) (2024), reported an average capacity factor of 92.7, while the American Nuclear Society noted a median capacity factor of 91.13% between 2020 and 2022 (Gallier, 2023).

[2] Licensing, site selection for initial projects, fuel considerations, engagement with national, regional, and local stakeholders, supply chain readiness, and financing

3. Floating offshore wind

Onshore wind power has historically led the renewable energy market, driven by significant cost reductions and technological improvements. However, with suitable land becoming scarce, the focus has shifted to offshore wind. Offshore wind technology is now deployed in two primary forms: bottom-fixed and floating wind turbines. While bottom-fixed turbines are limited to shallow waters, floating offshore wind opens the door to harnessing wind energy in deeper waters, unlocking vast new areas for renewable energy production. This is particularly relevant in the Norwegian context, as approximately 70% of the North Sea is considered too deep for bottom-fixed turbines. Consequently, this section examines floating offshore wind farms (FOWFs) within a Nordic context, focusing on technology and recent advancements.

3.1 Floating offshore wind in a Norwegian context

Norway has established itself as a leader in floating offshore wind technology, leveraging its extensive offshore expertise to advance renewable energy solutions. A pivotal project is Equinor's Hywind Scotland, the world's first commercial floating wind farm, commissioned in 2017. Located 25 kilometers off Peterhead, Scotland, it comprises five 6 MW turbines, totaling 30 MW of installed capacity, powering approximately 35,000 UK homes (Equinor , 2023).

Building on this success, Equinor launched Hywind Tampen in August 2023, the world's largest floating offshore wind farm. Situated about 140 kilometers off Norway's coast, it consists of 11 turbines, each with an 8 MW capacity, culminating in an 88 MW total installed capacity. Hywind Tampen supplies renewable energy directly to the Snorre and Gullfaks oil platforms, meeting around 35% of their annual power needs and reducing CO_2 emissions by over 200,000 tons per year (Equinor , 2023).

Furthering Norway's innovative approach, the GoliatVIND project by Odfjell Oceanwind plans to install five 15 MW floating wind turbines, totaling 75 MW, approximately 80 km northwest of Hammerfest in the Barents Sea. This project will utilize existing infrastructure by supplying renewable energy to the Goliat oil platform and the Hammerfest region, demonstrating efficient integration of renewable energy into established oil and gas operations (Odfjell Oceanwind, 2024).

3.2 Nordic scope

The Nordic region is well-positioned to become a key player in the emerging global FOW market, driven by innovative projects and growing commitments to renewable energy. Although there are few currently operational FOWFs in the Nordic region, significant efforts are underway to advance developments and unlock the potential of this technology in deep-water environments.

In Finland, the Wellamo project is a notable example, located in the Bothnian Sea, 90 kilometers off the coast. Covering a project area of approximately 1,000 km², Wellamo plans to develop between 1 and 2 GW of FOW installed capacity, potentially generating 10 TWh of renewable electricity annually (Eolus, 2023). Sweden is also advancing its FOW ambitions through multiple projects. A standout example is Deep Wind Offshore's initiative to develop a 1.5 GW floating offshore wind farm east of Stockholm. With phased development, this project has the potential to expand to a total capacity of 4.5 GW, demonstrating Sweden's strategic approach to scaling up its floating wind capacity (Deep Wind Offshore, 2024). Meanwhile, Denmark, recognized globally as a leader in wind energy, is investing heavily in FOW technology to enhance its existing bottom-fixed portfolio (TGS 4C Offshore, 2023). Additionally, the Danish government has set target to add 9 GW of offshore wind capacity by 2030 (Danish Energy Agency , u.d.).

Globally, the FOW sector is in its early stages, with a current installed capacity of 277 MW (IRENA, 2024). However, projections indicate significant growth, with operational capacity expected to reach 3-4 GW, or potentially 10 GW if aligned governmental policies facilitate expansion by 2030 (Wind Europe, 2024). According to DNV, the industry could achieve a 216 GW of floating offshore capacity by 2050, underscoring the long-term potential of this emerging technology (DNV, 2024).

3.3 Capacity Factor

The capacity factor is a critical measurement when calculating the energy output. For offshore wind, the capacity factor depends on several key factors, including weather conditions, hub heights, and the underlying technology (Nordhagen, 2024). Over the years, advancements in technology and the strategic placement of turbines have led to a significant increase in the capacity factor of OW. Estimates indicate a 76% increase from 1991 to 2023 globally (NREL, 2024). Projections suggest further increases in the coming decades, with the capacity factor expected to reach 47.18% by 2030, and 48.58% by 2050 (NREL, 2024).

Europe shows similar growth trends, with new offshore wind farms achieving capacity factors between 42% and 55%, up from 37% in 2018 (Wind Europe, 2023). For FOW specifically, limited data makes it difficult to establish a definitive capacity factor for this technology. However, the Hywind Scotland project achieved an impressive 57.1% over a 12-month period ending in March 2020 (Equinor, 2021). This exceeds the average capacity factors typically seen in bottom-fixed offshore wind (BFOW).

3.4 Technology

Offshore wind energy is captured through turbines placed either on BFOW foundations, secured directly to the seabed, or on floating foundations, anchored to the seabed with moorings. BFOW turbines are generally viable in waters shallower than 60 meters (Orsted, 2023). However, in regions like Norway, where waters are predominantly deep, BFOW turbines become impractical, leading to the necessity for floating offshore wind solutions.

3.4.1 Wind Turbines

A wind turbine converts kinetic energy into electrical power. Each turbine consists of a rotor, a nacelle, and a tower. The rotor, with its three blades, catches the wind and starts spinning. This spinning motion is transferred through a central hub and a drive shaft to the nacelle. Inside the nacelle, a gearbox increases the speed of the rotation, which then moves magnets around coils of wire to produce electricity. The nacelle also holds other equipment that monitors and controls the turbine (Orsted, 2023).

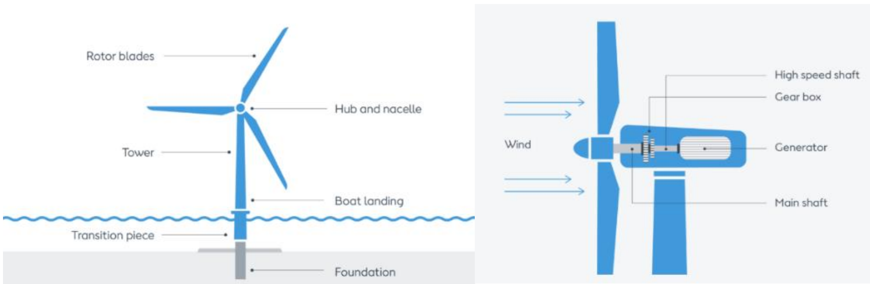

Figure 3.1: *Main components of a wind turbine and its internal mechanisms.*
Source: Orsted (u.d)

The development of offshore wind turbines has advanced significantly over the past decade, with an increase in both size and power capacity. In 2009, the average capacity of an offshore wind turbine in Europe was approximately 3 MW (Wikipedia, 2023). In 2020, this average had increased to 8,2 MW. Today, some of the most modern turbines can generate up to 15 MW of power (Odfjell Oceanwind, 2024)The physical size of wind turbines has also increased dramatically. In 2017, the longest turbine blade reached a length of 88,4 meters. Today, modern turbines can reach lengths exceeding 235 meters (Memija, 2024).

3.4.2 Foundation Types

Floating foundations are essential for deep-water offshore wind installations, with several innovative designs emerging in recent years. These foundations consist of large, buoyant platforms anchored by mooring lines, which provide stability for turbines even in deep waters and challenging sea conditions. Various designs for floating foundations include tension-leg platforms, semi-submersible platforms, barges, and spar buoys (Orsted, 2023). The selection of foundation technology differs across projects based on specific site conditions. For instance, the previously mentioned Hywind Tampen project uses a spar buoy design.

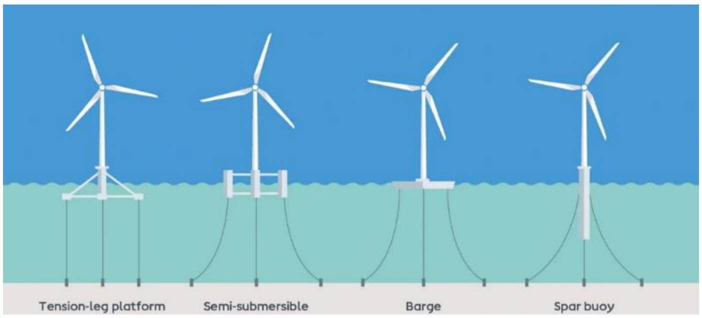

Figure 3.2: *Four types of foundation technology for floating offshore wind. Source: Orsted (u.d)*

3.4.3 Transformers

Electricity generated by the turbines is sent via array cables to an offshore substation. Here, the voltage is increased to reduce transmission loss. The power is then transmitted onshore using either high voltage alternating current (HVAC) or high voltage direct current (HVDC) cables, depending on distance and power requirements. HVAC is used for distances up to 80 km, while HVDC is suited for longer distances and higher capacities (Pillay, 2020). Another transformer on shore then steps the voltage down, integrating the electricity into the grid for distribution. Alternatively, electricity from the offshore substation can be supplied directly to nearby offshore oil and gas facilities or other large energy consumers operating off the grid, providing them with a reliable power source.

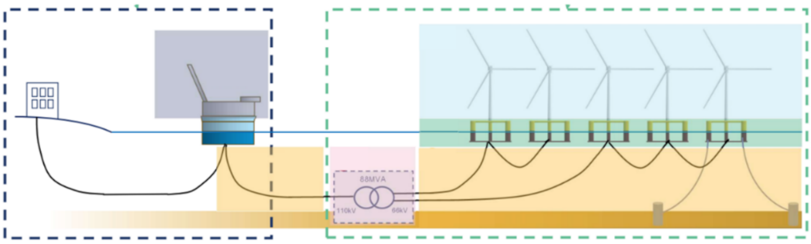

Figure 3.3: *Illustration of floating wind power supply to an oil platform. Source: Odfjell Oceanwind (2024)*

4. Power market overview

To fully understand the benefits of electrifying Norway's oil and gas sector, it is essential to consider the potential revenue streams from such an investment, both now and in the future. Offshore wind and nuclear power plants have estimated lifetimes that exceed most oil and gas installations in Norway. This allows them to continue generating income by selling electricity to other offtakers or directly to the grid after the platforms are decommissioned. Therefore, both the current and future markets for power will play a crucial role in shaping investment decisions in either technology. Although this thesis assumes the company uses all the power it generates, the power market becomes highly relevant after the platform is decommissioned and the power is sold to the grid. Therefore, understanding the broader international power market and the roles of its various participants remains essential.

4.1 Market infrastructure

Unlike other commodities, electricity cannot be stored on a large scale. This means that the market is dependent on an exact balance between generation and consumption (Energy Facts Norway, 2024). To achieve this balance, Norway introduced a market-based power trading system in 1991, becoming the first country to offer universal market access.

Norway is divided into five price zones based on their geography, linked by the electricity grid which spans across the country. The electricity grid is divided into three levels, namely the central, regional and distribution grid. The central grid functions as the "motorway system" for power supply, connecting power generators with consumers across the country. It also includes transmission lines that link Norway with neighboring countries, including Sweden, Denmark, and Finland. Through these links, Norway is further integrated into the broader European grid, including the Baltic States, the Netherlands, Germany, Poland, the UK, and Russia (Regjeringen, u.d.). The regional grids act as intermediaries, linking the central grid to local distribution networks. Energy-intensive industries are typically connected directly to the regional or central grids, while local distribution grids supply power to end users, including households, businesses, and industries.

The power market is divided into the wholesale and end-user segments. The wholesale market is further categorized into the day-ahead market, the continuous intraday market, and the balancing markets. The day-ahead market is the main trading platform where bids are submitted for physical power delivery the next day. Prices are set based on supply and demand, with the auction closing at 12:00 daily. In the event of unexpected changes in production or consumption, the intraday market allows participants to adjust these factors up to one hour before delivery. In the balancing market, the transmission system operator (TSO), Statnett in Norway, addresses imbalances during operating hours using reserves procured from the reserve market (Energy Facts Norway, 2024).

4.2 Pricing mechanisms

The electricity price is determined based on a set of price mechanisms. Each day, the Nord Pool power exchange publishes a system price, which is a fixed price for the entire Nordic market. This price is theoretical, based on the assumption that there are no bottlenecks in the grid. Its primary function is to act as a reference price for price setting, while the actual price of electricity is based on the supply and demand within the regions. This explains the significant variation in power prices across different regions in Norway, where some zones have notably higher prices due to greater demand.

Another key factor influencing electricity prices is the financial market, where derivatives like futures, forward contracts, options, and electricity price area differentials (EPADs) are traded. These instruments help market participants hedge against price volatility by locking in a fixed price over a specified period. They are most commonly used by market participants seeking price stability, such as energy suppliers, retailers and large industrial consumers, typically within energy-intensive industries. In addition, some traders and financial institutions use the instruments for speculative purposes, seeking to profit from price movements or to diversity their investment portfolio.

Lastly, PPAs offer a third alternative way of setting electricity prices. Statkraft is one of the leading PPA providers in Europe, offering renewable power supply contracts to corporations, municipal utilities, and redistributors across the country. As of today, Statnett provides renewable power from wind, solar and hydropower. PPAs support the decarbonization of the grid by aligning supply and demand, helping to manage the fluctuations of variable renewable energy, while stability is maintained through hydropower (Statkraft, u.d.). The long-term nature of these contracts distinguishes them from other financial instruments and can be used to secure offtake and hedge against price fluctuations up to 10 years in advance.

4.3 Market status

Over the past 12 months, Norway's total power consumption reached approximately 132 TWh (Statistisk Sentralbyrå, 2024). Figure 4.1 illustrates the trend in power consumption in Norway over the last decade, broken down by sector. Typically, consumption has ranged between 120 and 130 TWh, with a noticeable spike in 2021 due to unusually cold winter temperatures, which increased heating demand, coupled with higher industrial activity during the post-pandemic economic recovery (NVE, 2024).

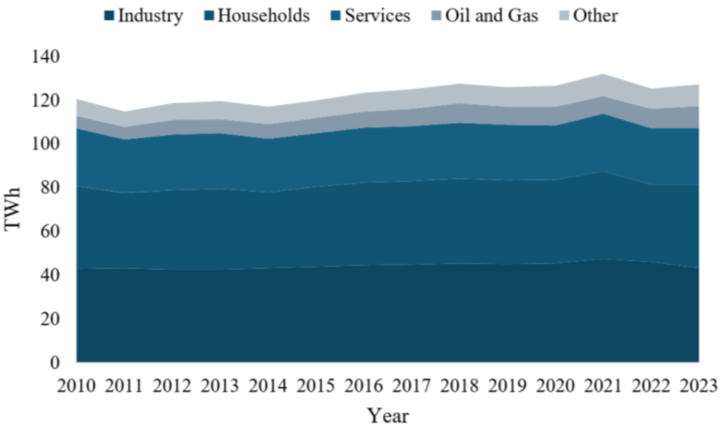

Figure 4.1: *Total electricity consumption by sector, 2010-2023, data from Statistisk Sentralbyrå (2024)*

In 2023, the industrial sectors consumed 34% of the total power, while households accounted for 30% (Statistisk Sentralbyrå, 2024). This variation in power consumption by sector is further influenced by seasonal demand. Norwegian power consumption is highly affected by seasonal variations, with significant differences in temperatures between summer and winter. In August, electricity usage averages just 4% of the annual total, while in January and December it can reach up to 25% (Ishavskraft, 2024).

Norway's energy mix is predominantly based on hydropower, which represented 89% of total electricity generation in 2023 (IEA, 2024). Wind power was the second largest contributor, accounting for 9% of total production. Natural gas plays a minor role in domestic power supply, contributing roughly 1%, while other sources, including waste, solar, and biofuels, make up only a small fraction of the overall energy mix.

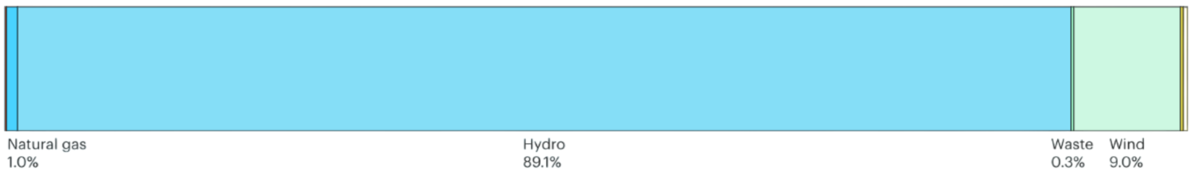

Figure 4.2: *Electricity generation by source, Norway 2023. Source: IEA (2024)*

Norway currently has 1,781 hydropower plants (Energifakta Norge, 2024). NVE estimates that approximately 216 TWh of hydropower potential is technically and economically feasible. Of this, about 64% has already been developed, and 23% is protected from development. The remaining potential is estimated at 23 TWh, which includes both new projects and upgrades or expansions of existing plants (NVE, 2020).

Expanding wind power has been a major priority for the Norwegian government in recent years, with the initial focus primarily on onshore wind farms. Technological advancements over the past decade have led to significantly lower costs and shorter construction times for onshore wind projects (Fornybar Norge, 2022). However, land-based wind farms must carefully balance environmental concerns, biodiversity protection, and the interests of local communities. To obtain a construction permit, developers must seek approval from the NVE, considering various stakeholder perspectives. The Fosen case illustrates these challenges, as the Supreme Court ruled in 2021 that the wind farms on the Fosen peninsula violated Sámi rights under the UN Human Rights Convention by interfering with reindeer herding. Consequently, the permit was declared invalid, and authorities are now working to find a solution that respects Sámi rights (Skogvang, 2024).

In addition to onshore wind, the government is increasingly focusing on offshore wind projects, both floating and bottom fixed. The recent opening of Hywind Tampen, the world's largest floating wind farm, demonstrates Norway's growing commitment to offshore wind energy (Energy Global, 2023). While floating wind farms have traditionally been more expensive than bottom fixed, the Norwegian continental shelf is largely too deep for bottom fixed installations (Andreassen, 2022). As a result, both technologies are being actively considered in the ongoing development of offshore wind capacity.

4.4 Demand outlook

According to Statnett, three main factors will drive electricity demand in Norway towards 2050. The first factor is the push for electrification aimed at reducing emissions, particularly by targeting high-emission sectors such as transportation, offshore operations, and heavy industry. The second factor is increased industrial and commercial activity. The European and global transition towards electrification is expected to significantly increase various electricity-based industrial processes, and Norway can potentially capture a share of this growth. The third, and perhaps most critical factor, is the availability of sufficient volumes of new renewable energy at competitive costs (Statnett, 2022).

Statnett estimates that by 2050, an additional 70 TWh of electricity will be required to meet the increased demand. Historically, electricity production in Norway has closely followed consumption, as shown in the graphs below, which illustrate the projected trends in both electricity demand and supply.

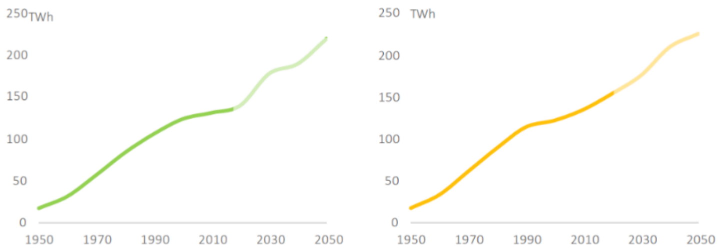

Figure 4.3: *Historical development in electricity consumption 1950–2022. Source: Statnett (2022)*

Offshore wind is expected to capture most of the forecasted production growth from 2030, of which at least half will be floating (Statnett, 2022). However, a significant increase in electricity consumption assumes that floating offshore wind becomes cost-effective enough to support an industry capable of competing internationally. This means that the current plan to reach Norway's goal of net zero by 2050, the costs related to floating offshore wind will need to decrease significantly over the next decade. The remaining capacity is expected to be taken by solar, onshore wind and some upgrades and extensions of hydro power (Statnett, 2022).

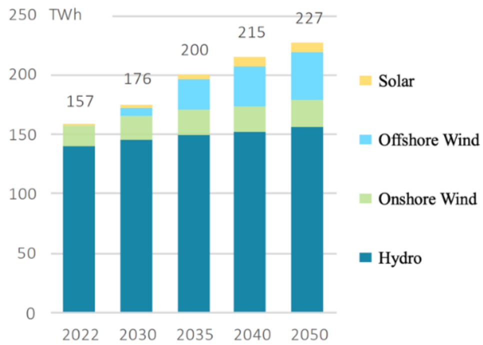

Figure 4.4: *Historical development in electricity production 2022–2050. Source: Statnett (2022)*

4.5 Price outlook

Predicting electricity prices is inherently uncertain, with estimates varying widely among experts. The price is influenced by numerous factors, and longer-term forecasts depend heavily on assumptions about future electricity production and the sources of that energy. Currently, there is a power surplus of approximately 17 TWh in Norway. However, Statnett projects that this surplus will shift to a deficit by around 2030, returning to a surplus by 2035. This temporary shortfall is expected as production capacity is likely to grow more slowly than demand in the early years, before accelerating as new capacity comes online and renewable technologies like floating offshore wind advance.

According to the principles of supply and demand, this deficit is expected to drive up prices until the electricity surplus is restored. Higher prices will likely attract more entrants to the market, as the potential for increased revenues becomes appealing. As more producers join and additional capacity is built to meet demand, prices should gradually decline as depicted in Figure 4.5.

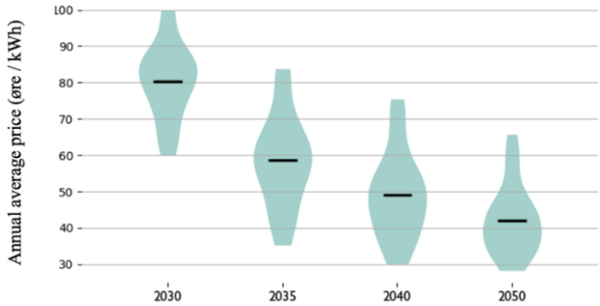

Figure 4.5: *Projected Norwegian power prices, 2030-2050. Source: NVE (2024)*

This price estimate represents NVE's base case scenario for power prices in Norway up to 2050. It's important to note that this projection reflects a national average, rather than being broken down into specific price zones, and it represents an annual average price rather than monthly or daily figures. Despite the uncertainty, the forecast provides a valuable benchmark for assessing potential revenues from the construction and operation of renewable energy projects.

5. Oil and Gas Market Overview

When oil and gas installations are electrified, the gas previously burned on the platform for power generation becomes available for sale alongside the regular volumes transported through the gas network. The price of this gas is a key factor in the financial analysis, as it represents a significant revenue stream for the project. Consequently, the following section explores the market infrastructure and trends that are likely to impact investment projects involving oil and gas installations.

5.1 Market infrastructure

Norway is one of the largest exporters of oil and gas in the world, and the combined value exceeds half the value of total Norwegian exports. The exported gas volume is equivalent to more than 30% of total EU gas consumption, with a total value of exported crude, condensate and gas in 2023 of NOK 1,200 billion (Norwegian Petroleum, 2024). In other words, oil and gas exports have historically been, and continue to be, key drivers of modern Norwegian society.

In Norway, we extract oil, gas and water in various combinations before it is separated and treated. Crude oil is a liquid comprised of different hydrocarbons. Crude natural gas, also known as rich gas, is a mixture of various gases, which in treated in a processing facility to separate the wet and dry gas components. Dry gas is more commonly known as natural gas, and contains higher levels of methane, as well as some ethane. Wet gas, or liquid natural gas (LNG), includes heavier gases like ethane, propane, butane, and naphtha.

On the Norwegian continental shelf, each license holder is responsible for selling the oil and gas they extract. The exception is Equinor, which also handles the sale of the government's share of production (SDFI share), as mandated by state directives. While all extracted oil is sold and exported, a portion of the gas is retained domestically for specific purposes. This includes generating electricity on-site, flaring for safety reasons, and reinjecting gas into reservoirs to help displace the oil (Norwegian Petroleum, 2024).

Unlike oil, which is a globally traded commodity delivered worldwide, gas markets have traditionally been more regionally segmented. However, the increasing production and trade of LNG have made gas markets more interconnected globally. Around 95% of Norway's natural gas is exported through a vast subsea pipeline system to Europe (Norwegian Petroleum, 2024).

5.2 Pricing mechanisms

The pricing mechanisms for oil and gas differ somewhat from those for electricity, primarily due to the global nature of the market. While gas is mainly exported through pipelines connecting European countries, a growing share is also shipped as LNG, allowing for broader global trade. In contrast, oil is predominantly transported by large tankers, enabling it to be shipped anywhere in the world. As a result, oil prices are set globally through benchmarks like Brent Crude, while gas prices are more heavily influenced by regional market dynamics and transport logistics.

Oil prices generally refer to the spot price of a barrel, 159 liters, of benchmark crude oil (Hofstad, 2024). The supply and demand principle are the main driving factor behind this price. Where there is an unbalance between the levels of supply and demand, the price of crude oil will rise or fall accordingly (Exxon Mobil, 2022). Other factors influencing oil prices include market participants such as hedgers and speculators. For example, an airline might purchase oil futures to protect against price volatility. Additionally, market sentiment can significantly impact prices; for instance, if investors anticipate an increase in demand, this expectation alone can drive oil prices higher globally (Kosakowski, 2024).

Gas prices, while following similar pricing principles as oil, are generally more influenced by regional market conditions. This is largely due to the reliance on transportation via pipeline networks connecting different regions. Although oil and gas prices often move in correlation, there are factors that impact gas prices more significantly than oil. One key factor is seasonal variation: demand for natural gas typically rises during colder months due to its use in heating homes and businesses (EIA, 2024). In contrast, oil demand is less directly affected by seasonal changes, as it is driven more by transportation and industrial needs. Additionally, factors such as storage capacity and pipeline infrastructure play important roles in determining the prices of natural gas and LNG.

5.3 Market status

Among oil and gas producing countries, the United States, Saudi Arabia, and Russia are the largest, with a combined average daily crude production of 43.79 million barrels (EIA, 2024). The top ten producers account for 73% of global crude oil production, while Norway contributes only about 1.7% (CEIC, 2024). In natural gas production, the U.S. and China lead, with Norway holding a 3% share of the global market. However, Norway’s share is more significant in the export market, as most other producing countries use a larger portion of their output domestically (Norwegian Petroleum, 2024).

Among Norwegian oil and gas companies, Equinor, Aker BP, Petrolo, and Vår Energi are the largest in terms of production licenses, respectively (Norsk Petroleum, 2024). In Norway, the production mix is evenly distributed between natural gas and oil, but some producers have a stronger focus on one segment over the other. Since 1971, oil and gas have been produced from a total of 123 fields on the Norwegian continental shelf. At the turn of 2023/2024, 92 fields were in production: 67 in the North Sea, 23 in the Norwegian Sea, and 2 in the Barents Sea. In 2023, four new fields started production, and 15 new fields were under development at the end of the year (Norsk Petroleum, 2024).

Since the oil price crash in 2014, and more recently due to the COVID-19 pandemic, investments in the oil and gas sector have declined (Lorentzen, 2021). Additionally, many investors anticipated a faster energy transition than what has occurred so far. As a result, the sector has experienced underinvestment for some time (Sokkeldirektoratet, u.d.). However, investments have significantly increased over the past few years.

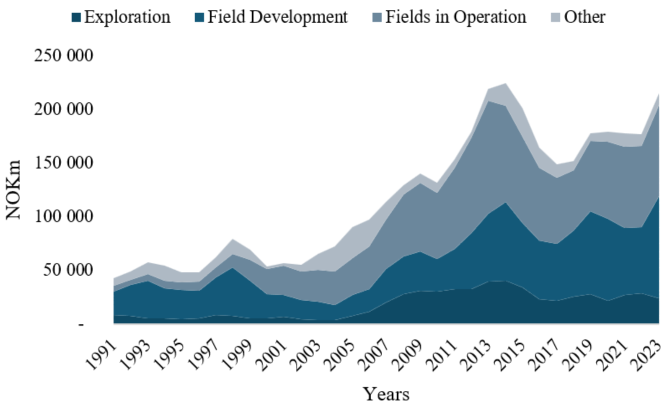

Figure 5.1: *Investments in the oil and gas sector, data from Statistisk Sentralbyrå (2024)*

5.4 Supply and demand outlook

Over the past 50 years, estimates indicate that around 55% of the recoverable resources on the Norwegian continental shelf have been extracted (Norsk Petroleum, 2024). Theoretically, this would suggest that we could continue exporting oil and gas for another 50 years. However, environmental concerns and the transition towards net-zero emissions make this scenario increasingly unlikely. Nonetheless, there is broad consensus in Norway that a sudden halt to all oil and gas extraction is not feasible. Instead, a gradual phase-out is preferred, allowing time for Norway and the rest of the world to transition away from fossil fuels. The future volume and price of oil and gas remain uncertain, with different organizations driven by their own views in regard to the energy transition offering varying predictions.

According to the IEA's medium-term outlook, the future of oil supply and demand will be influenced by the push towards clean energy and ongoing economic growth in emerging markets. The IEA expects global oil demand to peak by 2030, driven by a slowdown in advanced economies and the adoption of electric vehicles. However, strong demand from Asia and the aviation sector will continue to support oil use in the near term. On the supply side, a surge in global production capacity, especially from non-OPEC+ countries like the United States and Brazil, is projected to outpace demand growth. This could lead to a substantial increase in spare capacity, potentially creating an oversupplied market and pressuring producer economies to adapt their strategies accordingly (IEA, 2024).

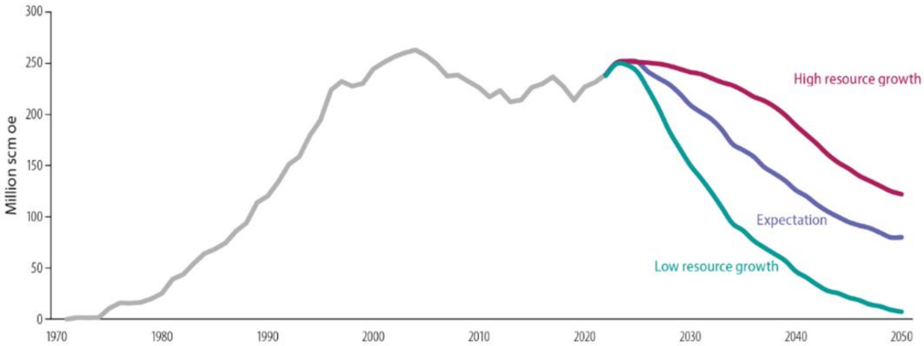

Figure 5.2: *Forecasted production development on the Norwegian continental shelf, 2022-2050. Source: Norwegian Offshore Directorate (2022)*

Figure 5.3 shows the forecasted production of oil and gas on the Norwegian continental shelf, published by the Norwegian Offshore Directorate. The forecast outlines three scenarios for oil and gas production on the Norwegian continental shelf until 2050. The Expectation scenario sees exploration continue at current levels before declining, with production halving by 2050, but losing economic importance. The low resource growth scenario forecasts a stagnation in exploration, fewer discoveries, and a sharp decline in investment, leading to lower production and significant economic restructuring. In contrast, the high resource growth scenario envisions increased exploration, successful discoveries, and advanced technology maintaining production levels and economic contributions (Norwegian Offshore Directorate, 2022).

5.5 Price forecasts

Predicting the future prices of oil and gas is inherently challenging due to the multitude of influencing factors, many of which are difficult to forecast accurately. As a result, price estimates often involve wide intervals and are heavily influenced by the underlying assumptions and outlook on the industry.

The chart below illustrates the price scenarios used by the Norwegian Petroleum Directorate, which are simplified with a 50% increase and decrease from a base case of USD 55 per barrel for the high and low scenarios, respectively.

Figure 5.3: *Projected future net revenues based on gas price scenarios, 2023–2050. Source: Norwegian Offshore Directorate (2022)*

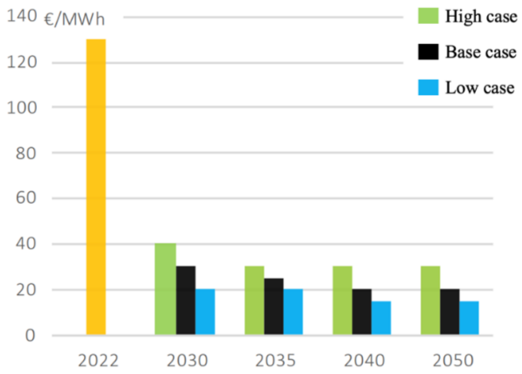

Figure 5.4: *Assumed future gas prices under different scenarios, 2023–2050. Source: Statnett (2022)*

In contrast, Statnett adopts different assumptions, leading to a base case gas price of 20 EUR/MWh for 2050. When converted to USD, this estimate is less than half of what the Norwegian Petroleum Directorate projects. These discrepancies highlight the inherent uncertainty in forecasting future oil and gas prices.

6. Electrification of oil and gas installations

The electrification of oil and gas installations in Norway has been a widely debated topic over several years. Most would agree that to meet the climate targets set by the Norwegian government and international agreements like the Paris Agreement, significant emission cuts are necessary. However, not everyone believes that investing limited resources in electrifying the Norwegian continental shelf is the most efficient way to reduce emissions. Although electrifying the platforms would eliminate the need to burn gas for operations and cut local emissions, critics argue that the environmental benefits may be limited (Nyhus, 2023). They suggest that the gas “saved” through electrification will likely end up being burned elsewhere, providing little real cuts in emissions. According to these critics, this strategy will simply shift the emissions beyond Norway's borders, rather than delivering genuine reductions.

6.1 Rationale for electrification

Initially, studies indicate that the argument presented above is not entirely accurate. While it is true that emissions are being shifted rather than fully eliminated, several important factors need to be considered. Among these are energy conversion efficiency, the potential for offsetting climate quotas, and a reduction in LNG production, which has higher emissions throughout its production and transportation value chain compared to pipeline gas (Thema, 2023). A report by Thema, commissioned by Offshore Norge, found that European emissions are reduced by roughly 80% of the initial emission cuts achieved through the electrification of Norwegian oil and gas installations.

Energy conversion efficiency is defined as the ratio of output energy to input energy (Singh, et al., 2022). In this context, it refers to the comparison between the energy yield from burning gas directly on the platform versus exporting it for use elsewhere. According to Thema, the average efficiency of using gas for power and heat generation in Europe ranges between 65% and 85%. In comparison, the efficiency on the Norwegian continental shelf is only around 35%. As a result, the potential emission reductions are substantial, as illustrated in an example from the same report for a hypothetical oil field.

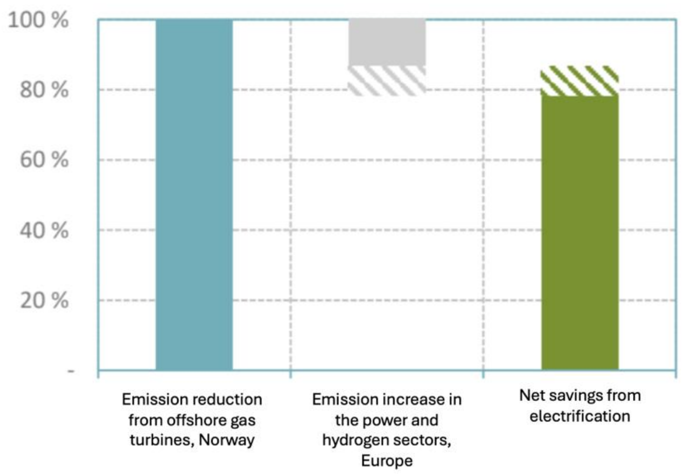

Figure 6.1: *Emission reductions for a hypothetical field. Source: Theam (2023)*

The second point raised in the Thema report concerns climate quotas. Here, climate quotas refer to the European Union Emission Trading System (EU ETS), a cap-and-trade system aimed at reducing greenhouse gas emissions in specific industries. Companies can receive or purchase emission allowances that can be traded, with the overall cap decreasing each year to align with the EU's climate goals (European Commission, 2024).

In the context of electrifying oil and gas installations, the Thema report highlights the potential for climate quotas to be cancelled as Norwegian demand for them decreases. The idea is that a growing surplus of quotas could lead to lower prices, increasing the likelihood of quota cancellations and a further tightening of the emissions cap (Thema, 2023). While this outcome is speculative and not guaranteed, it could serve as a secondary argument in favor of electrification.

Moreover, electrifying oil and gas installations allows the freed-up gas to be sold via pipelines to Europe. Estimates from Rystad Energy indicate that increased exports of Norwegian pipeline gas displace LNG imports by 90%. In other words, when Norwegian pipeline gas supply rises, LNG imports to Europe decrease by 90%, while European gas consumption grows by the remaining 10% (Thema, 2023). Rystad estimates that LNG imports to Europe emit over 70 kg of CO_2 per barrel, compared to just 7 kg for Norwegian piped gas (McGrath, 2022). This means the carbon footprint of piped gas is about ten times lower than that of LNG. Electrifying oil and gas installations in Norway could therefore help reduce emissions across Europe while potentially lowering both the demand for and future production of LNG.

As highlighted in the introduction, emissions from the oil and gas industry make up more than 25% of Norway's total emissions. In line with this, 20% of the emission reductions proposed by the Norwegian government are tied to the electrification of oil and gas installations. To assess the costs of electrification, it is essential to account for the avoided costs of emission quotas and the Norwegian carbon tax. If the total cost of electrification is lower than the combined cost of quotas and taxes, then electrification becomes the most profitable option. This point is also made in the Thema report, which notes that the electrification projects completed so far have been profitable. If similar electrification projects, expected to be profitable compared to the alternative of paying both quotas and taxes, are not pursued, it will likely become more challenging and costly to meet climate targets (Thema, 2023).

A final point worth addressing, though many others could be considered, is the importance of understanding the broader global context. While Norway is advancing in its transition to renewable energy, many countries around the world still depend heavily on coal, gas, and oil for their energy needs. Stopping oil and gas production in Norway would not only have significant economic implications for the country but could also lead to severe consequences for countries with limited access to renewable energy sources. According to the World Bank Group, developing countries face a "triple penalty" when transitioning to clean energy. They typically have to pay higher electricity costs, while lacking access to renewable energy sources, and therefore remain locked into a dependency on fossil fuels (World Bank Group, 2023). In such regions, a sudden reduction in supply would likely drive up electricity prices, causing energy insecurity and hindering economic growth.

This is not to suggest that Norway should indefinitely maintain oil and gas production, nor to undermine the urgency of the global energy transition. Instead, it highlights the current reality that many nations still rely on fossil fuels to power their economies. Phasing out oil and gas should be done in a responsible and strategic manner, taking into account the broader impact on global energy markets. In the meantime, Norway has a responsibility to make its industry as sustainable as possible, by implementing measures like electrification to reduce emissions and limit the carbon footprint of its operations. This approach allows Norway to continue supporting the global energy supply while contributing to climate goals through cleaner production methods.

6.2 Approach and implementation

In line with previous discussions, many oil fields in Norway have already been, or are planned to be, electrified. The Troll platform was the first to be partially electrified in 1996, and since then, numerous other platforms have undergone full or partial electrification. According to data from operators on the Norwegian continental shelf, electrification projects are expected to nearly double the electricity demand for the oil and gas industry by 2030 compared to 2022 levels (Øystese, 2024).

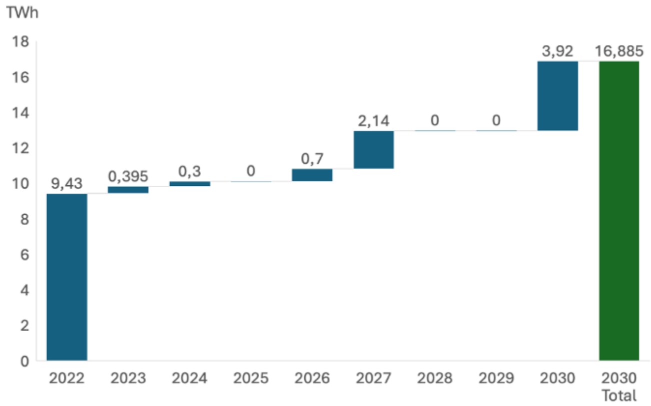

Figure 6.2: *Projected electricity demand for electrification initiatives in the Norwegian oil and gas industry, 2022-2030. Source: Øystese (2024)*

Major contributors to this increased power consumption by 2030 include the electrification of the Yggdrasil field, partial electrification of Troll B, full electrification of Troll C, partial electrification of Oseberg Field Center and Oseberg South, and the electrification of Draugen. All fields planned to be electrified by 2030 have received licenses to connect to the power grid, except for the Balder/Grane field (Øystese, 2024). Despite this, obtaining these licenses poses a challenge for oil producers, as approval is not guaranteed, even after the necessary platform and infrastructure upgrades. This is particularly challenging for the big electricity consumers, which are typically also the ones with the highest CO_2 emissions, as regional grids often lack the capacity to meet their substantial energy demands.

Another challenge is that industrial users, such as oil and gas producers, are typically less sensitive to electricity prices. When they are granted grid access, they can outbid other consumers, potentially driving up electricity prices for households and businesses. This forces the government to carefully assess whether regional grids can accommodate such large consumers, and in cases where they cannot, access is denied.

The increased demand for electricity must be met, or a significant electricity deficiency could occur by 2030. If grid-based solutions are not viable, alternative energy sources must be considered. Renewable energy, particularly wind power, is often proposed as the next-best option in Norway. Both offshore and onshore wind farms are under discussion as solutions for electrifying the continental shelf. However, wind power faces significant challenges. As a variable energy source, its output depends on weather conditions, leading to fluctuations that cannot provide the consistent, stable power supply required by oil and gas installations. To ensure reliability, wind power often needs to be paired with a grid connection, further complicating infrastructure requirements (Kristiansen, 2024).

Nuclear power, as explored in this thesis, offers an alternative. Unlike most alternative energy sources, nuclear power is not weather-dependent and can deliver continuous, stable electricity year-round (Kristiansen, 2024). This eliminates the need for additional grid connections required by wind power, potentially reducing infrastructure costs and avoiding competition with regional communities for power, thereby mitigating the risk of higher electricity prices.

Implementing either wind or nuclear power requires careful consideration of infrastructure needs. These include subsea cables, offshore substations, and onshore connection points. For platforms connected to the mainland grid, the connection process typically involves constructing a land-based converter station to transform alternating current (AC) into direct current (DC). DC cables then transmit electricity over the required distance to an offshore converter station, often located on an existing structure, where the current is converted back to AC. The power is then distributed to individual platforms via AC cables. For each platform, cables are routed through risers (new or existing) to a transformer, which supplies the platform’s various functions (Oljeindustriens Landsforening, 2003).

7. Theoretical review

The financial analysis presented in this thesis is grounded in established theoretical approaches and financial methodologies widely recognized in the field. This chapter provides a theoretical overview of the most relevant concepts used. Our financial analysis is divided into two parts: an investment analysis and a cost analysis, utilizing the discounted cash flow (DCF) and levelized cost of energy (LCOE) methods, respectively. Additionally, both analyses incorporate theories on calculating the cost of capital, commonly referred to as the weighted average cost of capital (WACC). The purpose of this chapter is to equip the reader with a clear understanding of the key financial concepts underlying the analysis, which form the foundation for the conclusions and discussions presented in this thesis.

7.1 Investment analysis: Discounted cash flow

Discounted cash flow is a valuation technique that calculates the present value of an investment by analyzing its anticipated future cash flows. This approach helps analysts assess the current worth of an investment by forecasting the income it is expected to produce over time (Fernando, 2024). In a DCF model, income can be represented either as direct revenues or as potential cost savings resulting from the investment, similar to how some “revenue” are treated in our financial analysis.

When considering whether an investment is worth the investment cost, one can assume different metrics. Common methods include NPV, IRR, and payback time. In this thesis, we focus on NPV, which measures the difference between the present value of cash inflows and outflows over time. Cash flows are discounted using an appropriate discount rate, providing the project's value in today's terms. Generally, projects with positive NPV are worth undertaking (Fernando, 2024). Typically, DCFs are used to calculate the enterprise value of an investment to determine the share price. However, as this analysis focuses on a project rather than a corporation, calculating EV to determine stock prices is not relevant. Therefore, these calculations have been excluded from our investment analysis.

7.2 Cost analysis: Levelized cost of energy

Similarly to the DCF framework, LCOE calculations rely on cash flow projections, but they focus exclusively on costs rather than revenue potential. Instead of assessing profitability, LCOE compares project costs to the electricity output the energy source is expected to generate. This metric is a valuable tool for assessing and comparing different energy production methods, enabling comparisons across projects of different scales, technologies, and locations.

LCOE represents the average cost of constructing and operating an energy asset per unit of electricity produced over its lifetime. Alternatively, LCOE can be seen as the average minimum price at which the electricity must be sold to fully cover production costs throughout the asset's lifespan (Corporate Finance Institute, u.d.). The LCOE of a project can be calculated using the following formula (Corporate Finance Institute, u.d.):

$$LCEO = \frac{\sum_{t=0}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

Where:
I = *the initial cost of investment expenditures*
M = *maintenance and operations expenditures*
E = *sum of electricity generated*
t = *year*
n = *asset lifetime*
r = *discount rate*

7.3 Capital cost

The discount rate used in the investment and cost analysis is calculated using the WACC. WACC is defined as a company's after-tax cost of capital, meaning it expresses in a single figure the total return required by both bondholders and shareholders for providing capital to the company (Hargrave, 2024). The WACC formula can be expressed as follows (Kinserdal, 2023):

$$\overbrace{\%\left(r_f + CreditRisk\right) \times (1-t) + \%\underbrace{(r_f + MP \times \beta)}_{\textbf{CAPM}}}^{\textbf{WACC}}$$

The risk-free rate (r_f) forms the foundation for estimating borrowing costs. The yield curve is the only theoretically correct method for determining r_f, but in practice, long-term government bond rates (e.g., ZCBs/T-bonds) are commonly used as substitutes. Credit risk is then added as a spread to the risk-free rate, reflecting the additional cost of borrowing beyond the risk-free rate. Credit risk tends to vary significantly, especially during periods of economic uncertainty, making it challenging to estimate borrowing costs. Kinserdal recommends estimating the cost of debt either as risk-free rate + credit risk, based on estimates from rating agencies or by applying the rule of thumb outlined in the table below.

Business profile	Stable (Volatile conditions)
Equity ratio > 50%, and stable industry	+1% (+2%)
quity ratio 20–50%, and potentially cyclical or newer business model	+2% (+3-4%)
Equity ratio > 20%, and potentially a venture, new, or distressed	+3% (>5%)

Table 7.1: *Rule of thumb for estimating credit spreads based on business profile and market conditions, input from Kinserdal (2023)*

The tax rate (t) applied is the nominal tax rate from the country where the external debt is located or where tax deductions occur. If the debt spans multiple countries, a weighted nominal tax rate is calculated across the relevant jurisdictions. For the weighting between debt and equity (%), net financial debt is used, sourced from a regrouping of the balance sheet. This is assumed to approximate the market value after taxes. For equity, market values are used as the basis for weighting. When the exact weights are unknown, an assumption of "normal financing" can be used, with Kinserdal recommending a ratio of 30% debt and 70% equity.

The final component of the equation presented above constitutes the capital asset pricing model (CAPM). This model describes the relationship between systematic risk, or market risk, and the expected return on assets, particularly stocks. CAPM establishes a linear relationship between the required return on an investment and the associated risk (Kenton, 2024). The inputs to the formula include the risk-free rate, as discussed above, along with the market risk premium (MP) and beta (ß). Approximation methods include using historical premiums, which vary depending on whether a geometric or arithmetic mean is used and the country chosen. Other methods involve implied premiums, which estimate the premium indicated by current stock prices, and surveys that ask investors about their expectations. As a rule of thumb, Kinserdal suggests assuming a market risk premium of 4% to 6%.

Beta measures the volatility or systematic risk of a security or portfolio compared to the market. Beta is effectively a measure of cyclical sensitivity, with a beta above one indicating higher risk than the market, and below one suggests reduced risk (Kenton, 2024). Kinserdal proposes a three-step process for estimating beta in practice. First, equity beta for comparable companies is identified. Next, the unlevered beta for these companies is calculated. Finally, the average asset beta is adjusted to reflect the company’s debt-to-equity ratio, yielding the final beta estimate.

8. Data

To outline the input factors used in our financial analysis, we will in this section review the relevant literature and data that assumptions in the financial models are based on. The inputs are categorized as fixed or variable, where the variable inputs will be presented across three scenarios. Each factor is discussed in detail below, including the data collected, the assumptions made, and the reasoning behind the final input selections. The methodology for determining key input factors has generally involved evaluating comparable projects based on their relevance to an electrification project in Norway. The key metrics considered are geographical proximity, technology design (SMR vs. conventional, floating vs. bottom-fixed), and recency. In certain cases, additional metrics or weights between estimates have been applied, which will be discussed where relevant.

8.1 Data Collection

The data collection for this thesis involved meetings with industry experts and the review of publicly available information from various relevant sources.

8.1.1 Meetings and conversations

During our research for this thesis, we engaged with a range of industry specialists and stakeholders to gather both quantitative and qualitative insights. Through discussions with Norsk Kjernekraft (NKK), we gained valuable information about their assumptions and the current status of nuclear energy in Norway, focusing on underlying challenges and operational aspects of nuclear power production. To deepen our understanding of nuclear power and the European and global markets for SMRs, we also consulted Associate Professor Jonas Kristiansen Nøland from NTNU.

For insights into floating offshore wind, we held a meeting with Odfjell Oceanwind, which provided information about the GoliatWind project, including cost estimates for connecting FOW installations to oil platforms and the associated challenges and opportunities with existing infrastructure. To incorporate the perspective of oil producers, we also met with a Head of Engineering at Vår Energi, who provided general input on the electrification of oil installations.

Additionally, we consulted the executive leadership in Karmøy municipality, which offered insights into their thermal district heating infrastructure, which has been useful in refining our assumptions. Lastly, Professor Finn Kinserdal from NHH offered insights into financing costs, further informing our financial modeling.

8.1.2 Research and reports

In addition to primary data from meetings, we relied on a variety of reports, analyses, and articles to supplement our understanding. The most used sources in our analysis include Norges Vassdrags – og Energidirektorat (NVE), DNV Group (DNV), National Renewable Energy Laboratory (NREL) and the U.S. Department of Energy (DOE), as they provided foundational data and insights into both nuclear and floating offshore wind technologies. However, other sources have also been incorporated throughout the analysis to ensure a comprehensive perspective.

The Technology Baseline developed by NREL, a U.S. Department of Energy laboratory, supplied cost and capacity factor estimates for both nuclear and floating wind technologies, though their U.S.-centric data required careful contextualization for Norwegian conditions. NVE provided estimates for floating offshore wind costs for 2024 and 2030, covering both floating and bottom-fixed options, alongside LCOE estimates for nuclear power. However, NVE's projections, particularly for the costs of wind farms, appeared optimistic compared to other sources and were approached with caution.

For FOW, DNV contributed data on market overviews and cost comparisons between floating and bottom-fixed technologies. BVG Associates, a consulting firm specializing in offshore wind technology, provided cost estimates for BFOW farms, which were adjusted using estimated cost differences between floating and bottom-fixed technologies. Additionally, a report from the Environmental Research Institute at the University College Cork in Ireland provided a detailed cost analysis of FOW in the Atlantic and North Sea regions. This report was a key resource for estimating cable and transmission costs.

For nuclear cost estimates, a memorandum authored by Carlsen et al. and published by the Swedish Ministry of Finance provided valuable data. While the focus on large reactors was less relevant to this analysis, the geographical proximity to Norway, along with similar regulatory environments and energy market structures, made the data a useful reference. Lastly, a DOE report on SMRs offered crucial insights into costs and future trends, forming an essential component of our nuclear analysis.

8.2 Inflation and currency adjustments

Given the inclusion of projects from various countries commissioned at different times, the data in this thesis includes figures provided in different currencies and from multiple years. To enable cross-currency comparisons, the values were converted to NOK using average exchange rates for the last twelve months. The FOW values were further adjusted for inflation using both historical and projected inflation rates from Statista, reflecting changes from the reporting year or project completion date. Generally, no such adjustments were applied to the SMR estimates, as these are presented in broad ranges and typically assume a starting point from 2030, given the limited commercial availability of the technology.

8.3 Financial analysis of small modular reactors

Before presenting our input assumptions, it is important to note that investments in SMR projects would only be feasible several years into the future. The assumptions are simplified and not based on operational SMR projects since very few are commercially available. Currently, only five SMRs are operational, and only the CNP-300 from China has a capacity of 300 MW (WNA, 2024). Except for depreciation and taxes, we have disregarded accruals and treat all items with a cash-flow effect in the period they occur. Furthermore, we mostly apply fixed average price levels for both income and costs, which means uncertainties related to price fluctuations, inflation, and market conditions are not captured.

Nuclear, Fixed	Unit	Value
Operational lifetime	years	60
Thermal capacity	%	-
Transmission loss (until 2050)	%	10 %
Transmission loss (after 2050)	%	-

Nuclear, Variable	Unit	Advanced	Base	Conservative
Capacity factor	%	93 %	90 %	89 %
Construction time	years	4	6	8
Overnight capital cost	NOKm	21 000	24 000	27 000
Development cost	NOKm	2 272	2 648	3 024
Fuel cost	NOK / MWh	30	40	50
First refueling	NOKm	750	874	998
Waste disposal cost	NOK / MWh	45	60	86
Fixed O&M	NOK / MWh	133	188	210
Total producion p.a. (incl. transmission)	MWh	2 199 636	2 128 680	2 105 028
Total producion p.a. (without transmission)	MWh	2 444 040	2 365 200	2 338 920
Total emission savings p.a.	tCO2	1 319 782	1 277 208	1 263 017
Total gass sold p.a.	MWh	6 284 674	6 081 943	6 014 366

Table 8.1*: Fixed and variable inputs utilized in the SMR financial analysis*

8.3.1 Production Capacity

Annual production capacity, expressed in MWh, can be calculated using the following formula:

$$MWh = Installed\ capacity\ (MW) * Capacity\ Factor\ (\%) * Hours\ in\ a\ year\ (8760)$$

To estimate annual production of a nuclear plant, it is necessary to assume a capacity factor. Capacity factor can be defined as the ratio of actual energy produced over a given period compared to the maximum energy the reactor could have generated operating continuously at full power during the same period (EIA, 2024). Nuclear reactors typically achieve a higher capacity factor compared to other alternative energy sources. Based on data collected from various sources on stated capacity factors for nuclear power plants, the most relevant given both geography and recency, are estimates presented by NKK, NVE, NREL and the Swedish memorandum, of 95%, 89%, 93% and 89%, respectively. Other estimates typically fall within a similar range, averaging between 85-95%.

As the nuclear plant is onshore and the installation offshore, transmission loss must be accounted for. Transmission loss occurs when electrical currents travel through a network, with some energy dissipating as heat due to electrical resistance (NESO, 2024). Based on conversations with Vår Energi, electricity transported from shore to the platform typically experiences 8-12% transmission loss. For this analysis, we will use an assumption of 10% transmission loss until 2050. After 2050, we assume no transmission loss between the nuclear plant and the grid, as the distance is expected to be minimal. Although this is a simplified assumption, we consider it the most reliable estimation method due to the limited data available for this specific situation.

8.3.2 CAPEX

The CAPEX for nuclear power plants can be broken down into individual components to reflect key cost drivers and the various project stages. In this thesis, CAPEX is divided into three components: overnight costs, development costs, and cables and transmission costs. This breakdown differs from most reported CAPEX figures for SMRs, as our case assumes significant costs for transporting electricity from shore to the installations. Based on our input data, the distribution among these three cost groups is shown in Figure 8.1.

Figure 8.1: *Fixed and variable inputs utilized in the SMR financial analysis*

Overnight Capital Cost

Construction costs, often referred to as overnight capital costs, are the largest component of the total CAPEX. The term "overnight cost" reflects the total cost of construction as if it occurred instantly, excluding financing expenses. Various methods are used to estimate the overnight cost of a project, but it typically includes construction expenses such as materials and site planning, machinery, electrical controls, and general project costs like labor and engineering (Energy Education, 2024).

These costs are heavily influenced by country-specific factors such as safety regulations, the competitive landscape, labor expenses, and expertise in similar large-scale infrastructure projects. Historically, labor costs have been a major factor driving overnight costs, explaining much of the variation between Western countries and others for conventional reactors. According to the Swedish Ministry of Finance, labor costs per MW were approximately 4 million NOK in South Korea and China, compared to 13 million NOK in the United States (Carlen, et al., 2024).

However, recent studies by the DOE on SMRs suggest that labor market differences have less impact on overnight costs compared to traditional reactors (U.S. Department of Energy, 2024). For large reactors, the range of possible outcomes is broader, with significantly higher upper-bound overnight costs in the U.S. and Europe compared to other regions. This suggests that SMRs are likely to have more uniform capital costs globally, with relatively small increases at the lower end and much narrower variations at the higher end compared to large reactors. As a result, Norway can expect SMR capital costs to align more closely with those in other regions, unlike the significant cost disparities seen with conventional reactors.

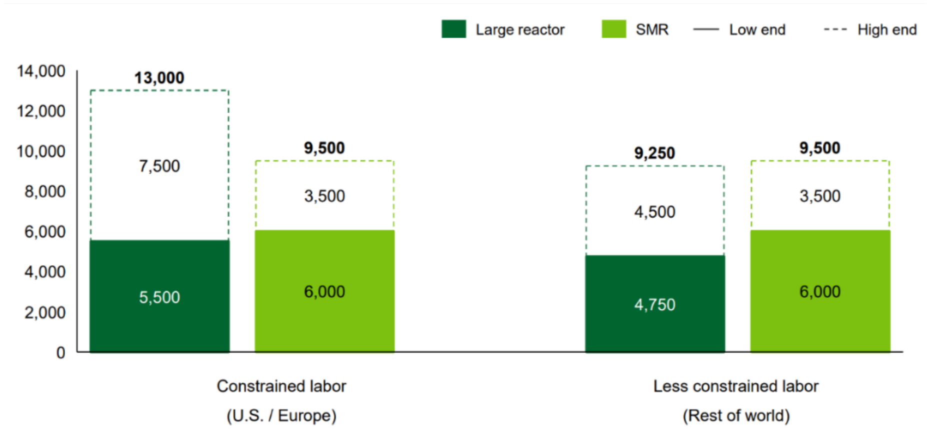

Figure 8.2: *Overnight costs by labor environment. Source: U.S Department of Energy (2024)*

Overnight costs can also be influenced by factors beyond specific countries or regions. Key considerations include the supplier's ability to deliver the project within planned budgets and timelines, the choice of reactor design, and the availability of a suitable plant site. Recent large-scale nuclear construction projects in Finland, France, and the United Kingdom have experienced significant cost and time overruns (Carlen, et al., 2024). While some plants have been completed within the planned timeframe, others in the United States and Europe have faced substantial delays. A study by Oxford found that the median cost overrun for such projects was 67%, with median delays of 40% (Budzier, et al., 2018). These overruns also increase financing costs as investment horizons are extended, increasing the LCOE estimates.

However, the outlook may not be as negative as these figures suggest. Jonas Nøland, Associate Professor in Energy Conversion at NTNU, noted in an article that while the cost of the recent Finish Olkiluoto-3 plant rose from an initial estimate of 3 billion to 11 billion euros, the LCOE remains competitive. When divided by the plant's total production capacity of 1,600 MW, the stated LCOE is 78 EUR/MWh, significantly below nuclear cost estimates from NVE (Nøland, 2024). Additionally, according to the MIT NCET report, the probability of cost overruns is much lower for SMRs compared to large conventional reactors. The shorter construction timelines and reduced number of individual tasks in SMR projects leave less room for errors. As a result, while the median cost per kW may be similar for both types of reactors, SMRs offer greater certainty in achieving projected costs (U.S. Department of Energy, 2024).

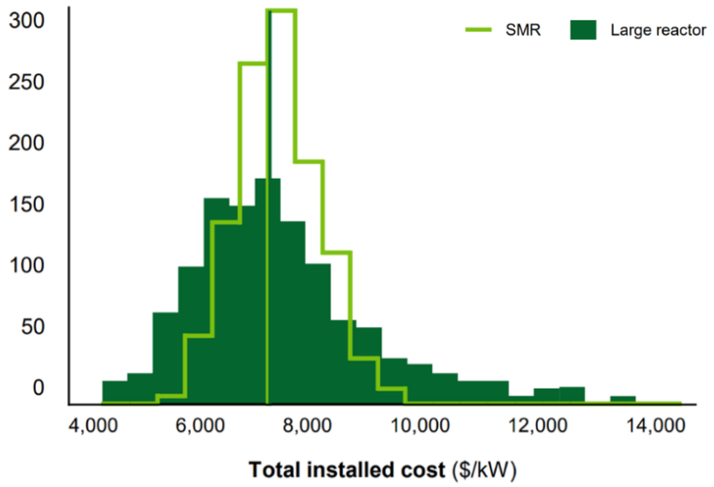

Figure 8.3*: Overnight capital costs probability distribution for BWRs, conventional reactors and SMR. Source: U.S Department of Energy (2024)*

Nuclear power projects can be divided into two groups. By First-of-a-kind (FOAK) projects, one typically refers to the first deployment of a specific technology, whether it is the first operational unit globally or the first plant of its kind constructed in a particular country or region. The second group is known as nth-of-a-kind (NOAK) projects, which are the projects following the initial FOAK project. The former is generally assumed to incur higher costs compared to NOAK projects. According to MIT, the average costs for NOAK projects are 30% higher than for subsequent ones, particularly when expertise in nuclear reactor construction and operation are still relatively new or in their early stages (Carlen, et al., 2024). Several factors contribute to this difference, with learning curves and economies of scale being among the most cited. Additionally, single-unit nuclear reactor projects with limited installations in a given area tend to drive up costs. This is because expenses for site preparation, licensing, and associated infrastructure are spread across fewer projects, leading to generally higher FOAK costs (Carlen, et al., 2024).

The Swedish memorandum identifies four key determinants of the success of a nuclear power plant project: 1) A primary responsible organization with experience in large projects, 2) A contract structure that incentivizes all suppliers to contribute to the project's success, 3) Contract management capable of handling necessary changes swiftly and effectively, and 4) A regulatory framework that allows flexibility for minor design changes without long delays. According to the memorandum, the likelihood of success for a nuclear power project increases significantly when these four determinants are met.

In conclusion, numerous factors influence the overnight capital costs of SMR projects. While there is abundant data on the overnight costs of conventional nuclear plants, comparable statistics for SMRs are harder to find, making direct comparisons challenging. However, due to the limited availability of data on specific cost components, deliberate decisions must be made about how comparable the two technologies are in different contexts. Literature estimates on the overnight costs used in this thesis are presented in Table 8.2.

Source	Year	Status	MW/ NOKm	SMR	Geography.
NREL	2024	Possibility study	85.6	Yes	U.S/Europe
US Department of Energy	2030	Estimates	82.9	Yes	US
AEP Climate Impact Analysis	2021	Estimates	82.4	Yes	US
Swedish Ministry of Finance	2024	Possibility study	81.6	No	Sweden
Olkiluoto-3	2024	Historical figures	80.0	No	Finland
Southwestern Electric Power Company	2020	Estimates	69.4	Yes	US
NKK	2030	Estimates	67.0	Yes	Norway
PacifiCorp FOAK	2020	Estimates	66.7	Yes	US
TVA	2019	Estimates	61.0	Yes	US
Arizona Public Service Company	2020	Estimates	60.0	Yes	US
Dominion Virginia Power	2020	Estimates	58.6	Yes	US
PacifiCorp NOAK	2021	Estimates	57.7	Yes	US
Energiforsk	2020	Historical figures	56.1	No	Global
Avista 2021 IRP	2021	Estimates	48.6	Yes	US
OECD	2020	Estimates	48.2	No	U.K
Idaho Power 2021 IRP	2021	Estimates	44.6	Yes	US
NuScale	2022	Estimates	30.5	Yes	US

Table 8.2: *Estimated overnight costs, data from various sources listed in the table*

Development costs

While some of the referenced literature includes preparation costs incurred prior to construction, we have chosen to include an additional cost component in the CAPEX, based on input from NKK. This component covers expenses related to design, licensing, procurement, and other preparatory activities before construction commences. According to the World Nuclear Association, such costs typically account for approximately 10% of the total CAPEX (WNA, 2023).

Although some of the overnight cost estimates already incorporate this expense, we find it appropriate to add this component to account for uncertainties stemming from the regulatory context in Norway. According to Wikborg Rein, the current Norwegian regulatory framework for nuclear power is fragmented and incomplete (Nilsen, et.al., 2024). The law firm recommends developing a comprehensive and tailored regulatory framework for nuclear power to provide clarity on requirements for demonstrating sufficient financial resources, as well as the management of radioactive waste and decommissioning. Based on this discussion, we find it likely that the preparation costs of an SMR project in Norway will be higher than in countries with established nuclear legislation.

Additionally, as further discussed in the investment case section, this project is assumed to be a FOAK project in Norway. Therefore, we expect higher costs related to processes such as licensing, regulatory compliance, and the establishment of necessary infrastructure and expertise for the technology. These factors introduce additional financial and operational uncertainties. To account for this, these costs have been incorporated into our development costs component to maintain a conservative approach.

8.3.3 O&M

O&M costs can be categorized into fixed costs and variable costs. Variable costs are typically expressed in NOK/MWh, with the two largest components being fuel costs and waste disposal costs. Fixed costs are expenses that remain constant regardless of production volume, including maintenance, staff salaries, security, and regulatory compliance. The three most relevant estimates in this context are from the Swedish memorandum, NVE, and NKK, as they are recent and tailored to conditions similar to those in this analysis.

Fuel cost

Fuel costs can be divided into first fuel load costs and annual fuel costs. First fuel load cost, which is a one-time expense, represent the initial costs of procuring, processing, and fabricating the nuclear fuel required to start a new reactor, covering the entire first core loading before regular refueling cycles begin. This cost, also referred to as the front-end cost, typically accounts for 20% of total fuel costs in modern reactors (WNA, 2023). Alternatively, it can be estimated as 3% of CAPEX, according to NKK. For annual fuel costs, NVE, the Swedish memorandum, and NKK estimate these at approximately 3% of total production costs, or around 40 NOK/MWh. To account for the uncertainty surrounding these estimates, we will use a 25th percentile decrease for the advanced scenario and a 75th percentile increase for the conservative scenario, reflecting a range of potential outcomes.

Nuclear waste disposal

Nuclear power plant waste must be securely stored to prevent radiation from harming people, animals, or ecosystems. Deep geological disposal is widely regarded as the most effective method for storing radioactive materials, ensuring long-term isolation from the biosphere, while leveraging stable geological formations that has remained unchanged for millions of years. This form of disposal also reduces the need for ongoing monitoring and maintenance, thereby minimizing future generational responsibility. Additionally, it also protects waste from human interference and mitigates risks posed by natural disasters such as earthquakes, floods, or extreme weather (WNA, 2024).

The nuclear industry is one of the few sectors that actively manages its own waste, with many countries maintaining repositories for used nuclear materials. Historically, the costs of nuclear waste disposal have varied significantly. In Sweden, the estimated cost of nuclear waste disposal is 31 NOK/MWh, while the Forsmark, Oskarshamn, and Ringhals reactors have reported disposal costs ranging from 46 to 87 NOK/MWh. NVE expects higher costs for Norway compared to the Swedish estimates, as the expense would need to be shared among fewer nuclear power plants. However, Norway may have a natural advantage for deep disposal due to the availability of unused mines that could potentially be repurposed as disposal sites. To maintain a conservative approach, we use NVE's projected cost of 60 NOK/MWh as the base scenario. Advanced and conservative scenarios are set at 45 NOK/MWh and 86 NOK/MWh, respectively, based on the cost range from the Swedish reactors to account for uncertainties in these estimates.

Fixed costs

The fixed costs of a nuclear power plant primarily encompass operations, maintenance, and reinvestments. To estimate these costs in our analysis, we reference the Swedish memorandum at 133 NOK/MWh, NKK at 188 NOK/MWh, and NVE at 210 NOK/MWh as the basis for our advanced, base, and conservative scenarios, respectively. These estimates account for smaller annual reinvestments as well as a major reinvestment required after 30 years of operation.

8.4 Financial analysis of offshore floating wind

The inputs for the FOW financial analysis are presented in Figure 8.3. This section outlines the data either in general terms or on a per-unit basis, adjusted to fit the specific characteristics of our project in the investment case section. Since FOW is an emerging technology with limited data from large-scale operations, these assumptions are necessarily simplified. Nonetheless, recent projects that have become operational in the last few years are more heavily weighted in our estimates, as their context closely aligns with our analysis.

FOW, Fixed	Unit	Value
Transmission loss (until 2050)	%	-
Transmission loss (after 2050)	%	10 %

FOW, Variable	Unit	Advanced	Base	Conservative
Operational lifetime	years	30	25	20
Capacity factor	%	57 %	49 %	49 %
Construction time	years	2	4	6
Turbine cost	NOKm	4 994	6 849	7 644
Foundation and installation cost	NOKm	5 412	7 423	8 285
Inter-array cables	NOKm	143	215	287
FOW to oil platform	NOKm	76	120	163
Development cost	NOKm	582	798	891
O&M cost	NOKm	399	441	504
Total producion p.a. (without transmission)	MWh	1 497 960	1 291 662	1 281 150
Total producion p.a. (incl. transmission)	MWh	1 348 164	1 162 496	1 153 035
Total emission savings p.a.	tCO2	898 776	774 997	768 690
Total gass sold p.a.	MWh	4 279 886	3 690 463	3 660 429

Table 8.3: *Fixed and variable inputs utilized in the FOW financial analysis*

8.4.1 Production capacity

The production capacity of wind farms has historically been relatively low compared to other energy sources such as hydro, coal and gas (Advanced Power Alliance, 2021). Fluctuations in wind speed directly impact energy production, with lower speeds reducing output and higher speeds enhancing it. Additionally, the capacity is often constrained due to high maintenance time and downtime caused by rough weather conditions. To obtain relevant data for our investment case, we referred to a master's thesis from 2022, which estimated wind speeds and turbine availability for a bottom-fixed wind farm in Norway near the Ekofisk field. The study calculated a capacity factor of 49.15%.

Other sources provide similar estimates for capacity factors of 15 MW turbines. For example, NREL assumes a base case of 48.75% for U.S. FOW. Conversely, Hywind Scotland reports a capacity factor of 57%, though this figure is based on preliminary estimates and has not been validated over a longer measurement period. These three estimates will therefore represent our base, conservative, and advanced scenarios, respectively.

As noted in the nuclear data section, transmission loss is also relevant here. Unlike the nuclear scenario, we assume minimal transmission loss between the wind farm and the platform, as they are assumed to be in close proximity. However, when electricity from the wind farm is transported to the grid, we apply the same assumption of a 10% transmission loss. Starting in

2050, when the oil installation is estimated to be decommissioned, this 10% loss is incorporated into our analysis.

8.4.2 CAPEX

As per Figure 8.4, the CAPEX for offshore wind farms can be divided into several cost categories, with the cost distribution being supported by a broad range of data sources. Given the limited availability of data on floating offshore wind, we have supplemented our analysis by incorporating data from bottom-fixed offshore wind installations. Existing literature and analyses indicate that longer distance to shore and deeper water typically correspond to higher CAPEX. Considering that floating wind farms are typically situated at greater distances from shore and in deeper waters than bottom-fixed installations, the data for relevant cost components has been adjusted to accurately reflect these distinctions.

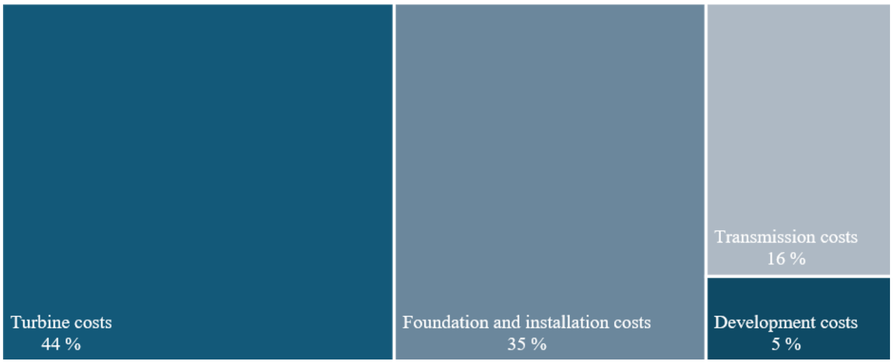

Figure 8.4: *SMR CAPEX split by cost component*

Turbine costs

The turbine is the most critical component of OWFs and represents the largest contributor to its CAPEX. According to DNV, the cost trajectory for floating wind turbines is expected to align with bottom-fixed wind turbines (DNV, 2022). Therefore, we will not differentiate between the two technologies when estimating turbine costs.

The collected data on turbine costs indicates a range from NOK 13.65 million to NOK 18.61 million per MW. The lower end, NOK 13.65 million per MW, was estimated by BVG in 2019, reflecting global trends in wind turbine costs, primarily for bottom-fixed systems (BVG, 2019). The upper end, NOK 18.61 million per MW, is derived from an analysis conducted by the University College Cork, with a focus on floating wind potential in the European Atlantic region (Martinez, 2021). NVE, concentrating specifically on the floating wind potential in Norway, provided a September 2024 estimate of NOK 16.55 million per MW, projecting a reduction to NOK 14.58 million per MW by 2030, driven by technological innovation and economies of scale (NVE, 2024). These estimates were averaged and adjusted for inflation to determine the cost distribution used in our final analysis, as shown in Figure 8.3.

Foundation and installation costs

Unlike turbine costs, floating foundation costs are estimated to be five times higher than those for bottom-fixed foundations. These higher costs are driven by factors such as limited experience, supply chain constraints, and the relative expense of components compared to bottom-fixed foundations (DNV, 2022). For example, a cost analysis by AFRY, an international engineering and advisory company, for a potential bottom-fixed wind farm in the Sørlig Nordsjø II area estimated costs at NOK 7.65 million per MW (AFRY, 2024). In contrast, NVE estimated the cost of floating offshore wind foundations in 2030, at a water depth of 300 meters, to be NOK 20,05 million per MW (NVE, 2024).

Installation costs encompass expenses related to setting up the wind farm, including hiring vessels for transporting and installing the turbines, as well as anchoring, mooring, and other associated activities. According to Martinez, these costs account for approximately 5% of the combined foundation and installation expenses of an OWF (Martinez, 2021).

This substantial difference in foundation costs highlights the impact of the chosen technology. Therefore, our financial analysis will focus exclusively on cost estimates for FOW foundations and installations. Incorporating the more optimistic estimates for bottom-fixed wind farms, despite their greater availability, would skew the analysis unnecessarily. Given the limited availability of relevant literature, we will base our estimate for foundation and installation costs on the NVE report as the base case scenario.

Development costs

Development costs in FOW consist of a variety of activities critical to the realization of a wind farm. These include planning, consenting services, environmental surveys, and detailed engineering. Currently, FOW development costs are higher than those of bottom-fixed wind farms, primarily due to its early stage of deployment (DNV, 2020). Bottom-fixed wind technology has seen widespread adoption and benefits from established supply chains, standardized processes, and a wealth of operational experience. In contrast, FOW technologies are still maturing, with limited commercial-scale projects executed to date. These factors lead to higher costs for planning, engineering, and risk management in floating projects, reflecting the complexity of anchoring systems, dynamic cabling, and floating platforms. For example, the Hywind Tampen project faced significant cost overruns, increasing partly due to increased planning, engineering, and risk management efforts required for its novel floating platform designs and anchoring systems (Energy Global, 2023).

Despite higher initial development costs, FOW is expected to achieve significant cost reductions as deployment scales, driven by accumulated experience and learning curve effects (DNV, 2020). By the time large-scale development begins post-2030, numerous floating wind projects will likely have been completed, leading to improved design processes, standardization, and risk management strategies that reduce costs. The Hywind Tampen project illustrates this trend. Despite cost overruns, it achieved a 35% reduction in investment cost per installed MW compared to Hywind Scotland, when adjusted for price developments since 2016/2017 (Energy Global, 2023).

The same approach used to estimate turbine costs was applied to development costs. Relevant estimates were averaged and adjusted for inflation to calculate the cost share of development as a percentage of total CAPEX, resulting in 4.4% in the base case scenario.

8.4.3 O&M costs

DNV (2021) projects O&M costs for FOW to be five times higher than that of BFOW. However, DNV also predicts that by 2030, the O&M costs for FOW will align with that of bottom-fixed installations.

Currently, BVG estimates the O&M costs for BFOW at NOK 1.68 million per MW when adjusted for inflation. Similarly, NVE projects the total O&M for BFOW in 2024 to be NOK 1.33 million per MW. Combining these estimates, and applying DNV’s multiplier for FOW, the OPEX for FOW in 2024 is calculated to be NOK 6.225 million per MW.

By 2030, DNV predicts that the O&M costs for FOW will align with those of BFOW. Therefore, a reasonable approach is to take an average of the two estimates mentioned above. Based on 2024 figures and assuming a learning curve that matches inflation, the base case OPEX is NOK 1.47 million per MW. This includes NOK 1.33 million per MW for the wind farm and NOK 140,844 per MW for cables and transmission.

8.5 Shared cost assumptions

Although the primary cost components in the investment analysis are technology-specific, certain additional costs are consistent across both technologies. This section focuses on the overlapping factors. Although there may be minor differences between them, these costs or cost component are largely similar on a per-unit basis, and thus they are presented here instead of being repeated separately for each technology. Any differences between the technologies will be discussed where relevant.

Shared cost assumptions, Variable	Unit	Advanced	Base	Conservative
Financing cost	%	5 %	6 %	7 %
Cable and transmission cost	NOKm	1 717,24	2 478,07	3 238,90

Shared cost assumptions, Fixed	Unit	Value
Installed capacity	MW	300
Market risk premium	%	5 %
Risk-free rate	%	3,8 %
Corporate tax rate	%	22 %
Gas transport tariff	NOK / sm3	0,04
Conversion efficiency	%	35 %
Emission factor	tCO2 / MWh	0,21

Table 8.4: *Assumptions for shared fixed and variable costs*

8.5.1 Gas transportation tariff

The surplus gas, previously utilized for platform operations, must now be integrated into the existing volumes transported through the pipeline network across the continental shelf. The transportation costs are estimated based on data from Gassco, the national operator overseeing gas transport from the Norwegian continental shelf. To estimate the most likely transportation cost, we calculated the average tariffs of the Oseberg Field Center, the Statfjord Field, and the Kårstø Processing Plant. These locations were selected to provide a representative sample based on their geographic distribution. Oseberg lies in the North Sea west of Bergen, while Statfjord is located in the Tampen area of the North Sea near the Norway-UK boundary. The Balder field, our reference field, transports its gas to Kårstø, situated along the Boknafjorden in Rogaland County, forming the third reference point in this analysis. To convert this value to NOK/MWh, we apply a conversion factor of 92.7 Sm^3/MWh.

8.5.2 Cable and transmission costs

Cables and transmission costs are heavily influenced by the existing infrastructure in the region. Currently, 16 oil fields, representing approximately 45% of Norway’s total offshore platforms, are either connected to or planning to utilize power from shore (Oljedirektoratet, 2020). For these platforms, transmission systems and cables connecting them to the grid are either operational or under construction. If we assume that such connections exist, integrating a nuclear power plant into the grid or adding floating offshore wind capacity would require relatively small additional investments in transmission infrastructure. However, in regions lacking such systems, costs increase significantly, as new subsea cables, offshore substations, and onshore connection points would need to be installed.

Martinez (2021) outlines a formula for calculating transmission costs in floating offshore wind projects, which can be adapted for nuclear power scenarios. The formula considers the length of the cables $d(x, y)$ multiplied by the number of export cables $\left(MW_{ex_{cab}}\right)$ and the cost per unit length of cable ($C_{ex_{cab}}$). Additionally, the formula accounts for the number of offshore substations ($MW_{off_{sub}}$) multiplied by their unit costs ($C_{off_{sub}}$) and the onshore substations ($MW_{on_{sub}}$) with their respective costs ($C_{on_{sub}}$):

$$Cables\ and\ transmission\ cost = d(x, y)n_{ex_{cab}}C_{ex_{cab}} + MW_{off_{sub}}C_{off_{sub}} + MW_{on_{sub}}C_{on_{sub}}$$

The costs of the power transmission to shore for HVDC and HVAC technologies are represented in Figure 8.5, where the break-even distance is estimated at 56 km.

Cost estimat	HVAC	HVDC
Cex_cab (NOKm/km)	27.17	12.98
Coff__sub (NOKm/MW)	0.453	1.660
Con_sub (NOKm/MW)	-	0.981

Table 8.5: *Cost estimates, cable and transmission.*
Source: Martinez (2024)

In contrast, NVE (2024) focuses solely on HVAC systems for both 2024 and 2030. The estimates include transport, installation, and development costs, which are treated separately from cable and substation expenses. NVE's cable cost estimates for HVAC are significantly lower than those provided by Martinez. However, NVE attributes higher costs to onshore substations while entirely excluding offshore substations from its analysis, resulting in the absence of cost estimates for this component.

Cost estimat	HVAC	HVDC
Cex_cab (NOKm/km)	6.93	6.36
Con__sub (NOKm/MW)	1.25	1.25

Table 8.6: *Cost estimates, cables and transmission.*
Source: NVE (2024)

As previously noted, in the absence of specific transmission cable estimates for a nuclear plant, we will approximate these costs using estimates from FOW projects. The primary distinction lies in the inter-array cables connecting the turbines, which are included as a separate cost component for FOW. Martinez (2021) addresses this aspect by incorporating an additional term into the formula, where the cost per kilometer is estimated at NOK 3.8 million/km. Other literature estimates the cost of inter-array cables per MW, with values ranging from NOK 477,750 to NOK 955,500 (BVG, 2019).

8.5.3 Financing costs

Determining the financing cost of both nuclear power and FOW investments requires careful consideration of various factors, as the chosen discount rate significantly impacts the profitability of the projects. For instance, according to the Swedish memorandum (2024), financing costs for a conventional nuclear power plant accounted for 62% of the LCOE when using a WACC of 7%, emphasizing how capital costs dominate the overall cost structure. However, the actual financing cost is not as straightforward as applying standard WACC or CAPM formulas, as real-world factors often introduce additional complexity. To derive an appropriate WACC for these projects, we employed both traditional valuation methods and alternative approaches.

Traditional Industry Peer Comparison

We began with an industry peer comparison, gathering data from six relevant companies in each sector. For nuclear, the selected peers were PSEG, Constellation Energy, Entergy, Dominion Energy, Southern Co., and Fortum. For FOW, the companies included Bonheur, Cadeler, Ørsted, Arise, RWE, and Nextera Energy. These companies were chosen based on their substantial exposure to nuclear or offshore wind, making them highly relevant for estimating WACC in this context.

Using monthly stock return data from Bloomberg and debt-to-equity ratios, we calculated levered and unlevered betas for each company relative to the MSCI World Index. For the cost of equity, we applied a risk-free rate of 3.80%, based on Norges Bank’s 10-year government bond yield (Norges Bank, 2024). Additionally, we applied a market risk premium of 5%, derived from PwC's 2024 estimate for Norway (PWC, 2023). This yielded a cost of equity of 7.06% for nuclear and 5.84% for FOW.

Debt betas were calculated at approximately 0.2 for nuclear and 0.1 for FOW, resulting in total costs of debt of 4.67% and 4.19%, respectively. Assuming “normal financing” of 70% equity and 30% debt and a corporate tax rate of 22%, the resulting WACCs were 6.04% for nuclear and 5.07% for FOW.

Practical Considerations Beyond WACC

The theoretical CAPM and WACC frameworks only partially capture the complexities of financing such projects. According to Finn Kinserdal, head of the Department for Accounting, Auditing, and Law at NHH, the critical question is what loan terms a bank would offer, which almost entirely depends on the specifics of the contract between the power producer and the buyer. Factors such as construction timelines, operational risks, and counterparty risks significantly influence the financing terms.

In our case, we assume that the oil producer enters into a fixed-price, long-term contract with itself, resulting in minimal financing risk. This scenario limits the relevance of CAPM or WACC, as the risks are specific to contract performance rather than market dynamics (Kinserdal, 2024). After the oil platform shuts down, we assume the remaining power is sold through the grid. This introduces slightly higher risk due to uncertain volumes and prices, though it remains outside the traditional CAPM/WACC framework, which assumes fully liquid markets and fluctuating prices (Kinserdal, 2024).

Kinserdal notes that nuclear and FOW investments, when operating in similar markets and with comparable operational risks, should generally have similar systematic risks, interest rate premiums, and required returns (Kinserdal, 2024). However, political risks for nuclear power, such as potential shutdown requirements after accidents, could lead to higher perceived risk over time. Conversely, FOW may face lower returns due to its variable energy supply, which could affect pricing variability.

Final Assumptions and WACC Application

Given the uncertainties and complexities in estimating financing costs, we have assumed a uniform WACC of 6% for both technologies in our analysis. This decision reflects our belief that the systematic risks of nuclear and FOW are comparable under the given assumptions. We account for uncertainties in construction costs through our financial modeling, presenting the financial analyses with a range of costs per MWh to capture variability.

While this analysis uses a base WACC of 6%, it is important to note that actual financing costs could deviate based on future market conditions, government policies, and the specific characteristics of the company managing the project. This interval approach ensures flexibility in addressing the uncertainties inherent in long-term energy investments. Finally, we assume that payments are distributed evenly across each year of the construction period, except for the first year, which only covers development costs.

8.6 Revenue

For the two potential technologies, the revenues or cost savings accounted for as revenues are identical on a per unit basis. However, differences in production capacity will result in varying total revenue figures, as discussed further in the investment case section. The key factors influencing revenues in a project to electrify an oil and gas installation primarily include gas prices, electricity prices, and the CO_2 quotas and taxes incurred if electrification is not implemented.

Revenues	Unit	Advanced	Base	Conservative
Electricity price	NOK / MWh	800	590	420
Gas price	NOK / MWh	479	359	239
Carbon quotas and taxes, 2030	NOK / tCO2	2997	2410	800

Table 8.7: *Shared revenue assumptions*

An important consideration is the potential cost savings from no longer running the gas turbines currently used to generate electricity for the platforms. These savings have not been included in this analysis. Instead, we have chosen to exclude the cost of operating a small grid connection facility, as reliable predictions for this cost are difficult to find. However, according to NKK, this cost would be significantly lower than the potential savings, making this a conservative assumption. Including these factors would likely have improved the investment case for both SMR and FOW.

8.6.1 Gas prices

As discussed in the oil and gas market outlook section, predicting future prices is extremely challenging, and very few sources publish estimates beyond 2030. These estimates will nonetheless have a significant impact on the investment analysis and the profitability of any energy-generating investment. To establish a price baseline for each scenario, we have chosen to use fixed prices in our analysis, as forecasting gas and electricity prices is outside the scope of this thesis. While this approach has limitations, it ensures consistency as we apply the same method to both SMR and FOW. Consequently, while the analysis may not provide the most accurate assessment of the revenue streams for such an investment on a standalone basis, it remains useful for comparing the two energy sources.

Furthermore, the estimated revenues will not be included in any LCOE calculations, making them comparable to other renewable alternatives. The price estimates for the three scenarios are based on Statnett's projections for advanced, base, and conservative scenarios. Although Statnett provides price trajectories through 2050, we have opted not to speculate on prices beyond 2030, as such predictions are heavily dependent on the underlying assumptions of the forecaster. For this reason, we use their 2030 estimates consistently throughout the analysis period.

8.6.2 Electricity prices

The same reasoning applies to electricity prices, particularly since the project does not generate revenues from electricity sales directly until after 2050, when the platform is decommissioned. Another important point to note is that electricity prices might be determined through some form of a PPA. The pricing of such contracts is even more challenging to predict, as it will depend heavily on the availability of renewable energy for large industrial consumers in 2050 and beyond. Further discussion on potential government subsidies is included in the discussion section.

The power price estimates for the three scenarios are derived from an NVE report on the power market's development toward 2050. The high-case scenario uses the estimate for 2030, the base case relies on the 2035 estimate, and the conservative case is based on the 2050 projection.

8.6.3 Carbon quotas and taxes

The Norwegian Ministry of Finance has established regulations on how emissions should be incorporated into economic analyses of government measures. Carbon price trajectories are updated annually, and this thesis relies on the trajectory published for 2024. For the petroleum sector, the base line price per ton of CO_2 is 2410 NOK from 2030. The publication also presented estimates for advanced and conservative scenarios from 2030 to 2050, with increasing values over time, used as our advanced and conservative scenarios (Regjeringen, 2023).

The total annual savings from carbon quotas and taxes depend on the CO_2 emissions the installation would have produced if it had continued burning gas instead of switching to electrification. The CO_2 emissions per MWh of burned gas can be determined using the formula:

$$tCO_2 = \frac{Total\ production\ volume\ (MWh) * Emission\ factor}{Conversion\ efficency}$$

As noted in the electrification section, gas conversion efficiency on Norwegian oil and gas installations is typically around 35%. According to Miljødirektoratet (2022), the emission factor for natural gas is approximately 0.21 tCO_2/MWh. To calculate total emissions from electricity production for each technology, this formula can be applied to the production volume. The result can then be multiplied by the price of carbon quotas and taxes to determine the total revenue, or in this case cost savings, for each technology.

9. Investment case

In this section, we will review the estimates discussed in the data section, tailored to our specific project assumptions. Both DCF and LCOE model results for the two technologies will be presented, with findings discussed and compared in the discussion section.

9.1 General project assumptions

Some key underlying assumptions for the financial analysis include the location of the reference platform, as this affects both the distance from shore and the water depth. While we have aimed to make the financial analysis as general as possible to ensure relevance for a wider range of platforms, selecting a reference platform is necessary to create a comprehensive and realistic cost framework.

For this analysis, we have chosen the Balder field as the reference. Located 165 km off the coast of Karmøy in the North Sea, just west of the Grane field, Balder sits at a water depth of 125 meters. Balder was selected because it can be considered representative of many other platforms in the North Sea in terms of distance from shore and water depth. Additionally, it is the only field currently planned for electrification before 2030 that has not yet been granted a license to connect to the grid. The field is operated by Vår Energi, which is actively exploring alternative electrification solutions outside of grid connection. This makes Balder particularly relevant for illustrating the costs associated with electrification using nuclear power or offshore wind. While this analysis serves as a preliminary feasibility study rather than a comprehensive evaluation, it provides an initial cost overview as a foundation for further analysis.

The presented analysis compares the two technologies based on a 300 MW installed capacity, with no existing transmission network connecting the platform to shore. Although the Balder field requires only 120 MW to fully electrify its installation, we have assumed that the entire 300 MW will be utilized by the Balder field and other nearby oil installations. As mentioned earlier, this assumption is made to maintain relevance for other potential electrification projects, enabling an evaluation of the full revenue potential from offsetting costs associated with carbon quotas and taxes imposed on the oil and gas industry. We consider this a reasonable assumption, as such a project could secure purchase agreements with either other oil companies in the region or other energy-intensive industries subject to carbon taxes.

Balder is expected to remain operational until 2050, after which the platform is anticipated to be decommissioned. Due to the longer lifespans of both nuclear power and offshore wind, assumptions must be made regarding the future use of the installed infrastructure after the platform shuts down. We have assumed that both technologies will utilize connections to shore to sell power directly into the grid. This means that both will bear the cost of laying the cables between the platform to shore of 165 km. For nuclear power, this scenario or a PPA with other platforms or industrial players could be equally plausible. For FOW, there are additional possibilities, such as decommissioning the turbines due to their limited remaining lifespan or relocating them to other sites. These costs are challenging to estimate accurately as they are projected far into the future, and the electricity production landscape in 2050 remains uncertain.

As a result, to maintain unbiased and comparable estimates, we have assumed that both SMR and FOW will sell the electricity to the grid. This implies that from 2050 onward, the cost savings associated with carbon quotas and taxes will no longer apply. We consider this a reasonable assumption, given that the world is aiming for net-zero emissions by 2050. By that time, it is unlikely that there will be offtakers without access to clean energy sources in Norway.

In our financial analysis, we have set the DCF models for both SMR and FOW to commence in 2030, aligning with the anticipated start of construction for these projects. This timeline reflects the extensive planning, regulatory approvals, and technological advancements required for such large-scale energy initiatives. For instance, SMRs are projected to become commercially viable in the early 2030s, necessitating a realistic assessment of their deployment schedules. Similarly, while FOW technology is advancing, large-scale commercial deployment is expected to ramp up around the same timeframe.

Regarding ownership structure, the financial analysis is conducted from the perspective of an oil and gas producer. This approach highlights the specific role of carbon quotas and taxes, often regarded as key financial drivers behind electrification efforts. While Balder is owned and operated by Vår Energi, we do not use this specific company’s financial characteristics in the financing cost discussion to ensure the analysis remains broadly applicable to other potential electrification projects.

9.2 SMR investment case

This section provides an in-depth analysis of the key factors influencing the investment case for a SMR project. Drawing on data and assumptions outlined in the earlier sections, the following subchapter detail the specific criteria for our project, including production levels, operational lifetime, construction time, CAPEX, and O&M costs. These inputs will be combined to calculate the project’s DCF and LCOE, forming the basis for evaluating its financial viability.

9.2.1 Production level

The production level of the SMR is a key factor influencing several variable inputs in our analysis, including revenue, fuel costs, and waste disposal costs. As such, the estimated production level plays a significant role in the feasibility of an SMR investment project.

Project characteristics

This analysis focuses on an SMR with an installed capacity of 300 MW. Specifically, the analysis is based on the BWRX-300 reactor, manufactured by the Japanese company GE Hitachi Nuclear Energy (GEH). This reactor was selected based on materials from NKK, which identified it as the most suitable option in a Norwegian context.

Capacity factor

The determined capacity factor is set to 90% in the base scenario, in accordance with NKK and Rystad estimates. In the advanced scenario, the capacity factor is estimated at 93%. The lower bound is set at 89%, aligning with projections from NVE and the Swedish memorandum. The latter estimates are based on conventional nuclear power plants with capacities of 1,600 and 1,250 MW, respectively. Therefore, we consider the estimates provided by NKK and Rystad to be more relevant for this analysis.

Total annual production volume

The annual production volume, expressed in MWh, can be calculated using the formula:

$$Annual\ production\ volume\ (MWh) =$$

$$Installed\ capacity * Hours\ in\ a\ year * Capacity\ factor * (1 - transmission\ loss)$$

$$= 300MW * 8760h * 90\% * (1 - 10\%) = 2{,}128{,}680\ MWh$$

Based on the provided capacity factors and assuming a 10% transmission loss until the platform's decommissioning in 2050, the total production capacity for the base case of the

SMR plant is calculated as 2,128,680 MWh. It is important to note that this production volume applies only until 2050, when the platform is decommissioned. After this point, the transmission loss is eliminated, increasing the production volume to 2,365,200 MWh.

Surplus gas volumes

Given the presented conversion efficiency and total annual production volume, the amount of gas the platform would have needed to burn to produce the same energy as the nuclear power plant can be calculated as:

$$Total\ gas\ required\ (MWh) = \frac{Total\ production\ volume}{Conversion\ efficiency} = \frac{2{,}128{,}680}{0{,}35}$$

This results in 6,081,943 MWh of gas, reflecting the lower conversion efficiency of gas burned on the platform. This figure now represents the amount of gas that is freed up for sale, as the nuclear power plant eliminates the need to burn gas for electricity production.

Total emission savings

Assuming the total production volume, emission factor, and conversion efficiency presented, we can calculate the total CO_2 emission savings per year. Applying the formula from the data section:

$$tCO_2 = \frac{Total\ production\ volume\ (MWh) * Emission\ factor}{Conversion\ efficency}$$

$$tCO_2 = 2{,}128{,}680 * \frac{0{,}21}{0{,}35} = 1{,}277{,}208$$

This value represents the total tons of CO_2 that no longer incur taxes and quotas due to electrification. Multiplying this amount by the price of taxes and quotas, which in the base case is assumed constant at 2,410 NOK per ton, results in total annual savings of approximately 3,078 million NOK.

Thermal capacity

An important factor to consider when discussing production levels is thermal capacity, which refers to the excess heat generated by the reactor. Nuclear reactors produce surplus heat that can be used for district heating if the necessary infrastructure is in place. However, Norway has limited district heating infrastructure, particularly near offshore oil and gas installations, so this potential revenue stream has been excluded from our financial analysis. After consulting with Karmøy Municipality, we confirmed that no district heating infrastructure currently exists in the area, further supporting this conclusion. It is worth noting that this conservative assumption could present a potential upside to the investment case if excess heat is utilized in the future.

9.2.2. Operational lifetime

The standard expectation for the operational lifetime of nuclear power plants in our reference data is 60 years, which aligns with the stated lifetime of the BWRX-300 reactor (GE Hitachi Nuclear Energy, 2024). While some of our reference data points assume that upgrades can be utilized to extend the operational lifetime of nuclear power generators, we have opted to use the industry standard of 60 years. This assumption remains consistent across all scenarios, despite both NKK and the Technology Baseline report from NREL suggesting an advanced-case lifetime of up to 80 years (NREL, 2024). NVE differs from most of our reference data by using an expected lifetime of 40 years (NVE, 2024). We have chosen not to emphasize this data point, as it represents a conservative estimate, particularly since it pertains to conventional reactors, whereas our focus is on SMRs.

9.2.3 Construction time

Construction delays are an important factor to consider when evaluating the total build time for an SMR. While research suggests that SMRs are less likely to experience significant time overruns, we still consider delays to be a notable risk. Although a construction delay of a few years may appear insignificant relative to an assumed 60-year operational lifetime, it can have a significant impact due to the effects of discounting. Delays extend the period without cash inflows while increasing costs, both of which considerably diminish the project's net present value. Based on relevant literature, we have set the base case construction time of 6 years, with 4 years as the advanced scenario and 8 years as the conservative scenario. While GEH's stated construction times for the BWRX-300 range from 24 to 36 months, our estimate is intentionally conservative given that this would be a FOAK project in Norway.

9.2.4 CAPEX

Considering the discussion in the Data section, the assumed overnight cost is based on the observations most relevant to the parameters of this thesis. The estimated range for overnight capital costs is 70-90 million NOK per MW. This assumes that the BWRX-300 reactor has reached a commercial state in other regions and can thus be classified as a NOAK project. However, as this would be the first SMR investment in Norway, it would still be considered a

FOAK project within the Norwegian context. Accordingly, no learning curve has been assumed in either scenario. However, overnight costs are expected to decrease for subsequent reactors if they are constructed in the same area and follow the same design, though this is not reflected in this analysis.

Scenario (NOKm)	Advanced	Base	Conservative
Overnight cost	21 000	24 000	27 000
Transmission cost	1 717	2 478	3 239
Development cost	2 272	2 648	3 024
Total CAPEX	24 989	29 126	33 263

Table 9.1: *Final CAPEX assumptions, SMR*

Regarding the four critical factors influencing the success of a nuclear power project, Norway appears relatively well-positioned for an SMR project. The involvement of a major industrial player, such as Equinor or Aker BP, offers significant advantages. These organizations, while lacking specific nuclear expertise, possess extensive experience in managing large-scale offshore projects. Furthermore, Norway's history of operating nuclear facilities for scientific purposes provides a foundation for leveraging domestic expertise and incorporating lessons from similar international projects.

Additionally, if government perspectives on nuclear power become more supportive, it is likely that a legal framework could be established to allow for flexibility in design adjustments without causing significant delays. A successful project would also require a contractual structure that aligns supplier incentives with the project's success, along with efficient contract administration capable of handling necessary changes promptly. This combination of factors could significantly enhance the likelihood of a successful SMR deployment in Norway.

To estimate the total cost of cables and transmission, we use the formula presented in the Data section. The distance from shore to the oil platform ($d(x, y)$) is set at 165 km, while the power generated from the nuclear power plant is estimated at 300 MW. These values remain constant across all three scenarios. However, the cost estimates for the export cables (C_{ex_cab}), the offshore substation (C_{offsub}), and the onshore substation (C_{onsub}) vary between the scenarios.

To calculate the cost of export cables, we averaged the estimates from Martinez (2021) and NVE (2024) for the base scenario. For the conservative and advanced scenarios, we used the individual estimates from Martinez and NVE, respectively. This results in cable costs of NOK

9.97 million/km, 13.58 million/km, and 6.36 million/km for the base, conservative, and advanced scenarios.

For the onshore substation, we applied the same methodology as for the cables, resulting in costs per MW of NOK 1.11 million, 1.25 million, and 0.98 million for the base, conservative, and advanced scenarios. Offshore substation costs were based solely on estimates from Martinez. For the base scenario, we used their estimate directly (NOK 1.66 million/MW). For the conservative scenario, this estimate was increased by 25%, resulting in NOK 2.07 million/MW, and for the advanced scenario, it was reduced by 25%, resulting in NOK 1.24 million/MW.

For the base scenario, the total cost of cables and transmission is calculated as follows:

$$Cables\ and\ transmission\ cost = 165 \times 1 \times 9.97 + 300 \times 1.66 + 300 \times 1.11 = 2{,}478$$

The total costs for the conservative and advanced scenarios are NOK 3,238 million and NOK 1,717 million, respectively. These estimates align closely with NKK’s projection of NOK 2,000 million for cables and transmission costs.

9.2.5 O&M

The total annual O&M cost includes fuel costs (with first refueling included only in the first operational year), waste disposal costs, and fixed costs. From the second year onward, when the additional fuel cost from the first year is excluded, the total O&M cost is calculated using the following equation:

$$Annual\ O\&M\ cost = (fuel\ cost + disposal\ cost + fixed\ cost) * 300 * 8760 * 0.9$$

This calculation results in a base case O&M cost of NOK 681,2 million per year. Given the high uncertainty surrounding these estimates, we have chosen to keep the O&M cost constant throughout the entire investment period. Although one could argue that costs would increase over the plant's lifetime due to equipment aging and deterioration, we have accounted for potential reinvestments in the CAPEX to mitigate these effects. Furthermore, SMRs have a more standardized design compared to conventional reactors, which could lead to reduced maintenance downtime and more efficient upgrades. Based on this, it is reasonable to assume that any increase in costs due to aging equipment will be less significant than for traditional nuclear power plants. As a result, we applied an annual estimate of NOK 681.2 million for the project's entire operational lifetime in the base scenario, NOK 508.4 million in the advanced scenario, and NOK 811.5 million in the conservative scenario.

9.3 FOW investment case

This section examines the cost components and financial viability of a FOW farm under the assumed project parameters. By analyzing production levels, operational lifetimes, construction timelines, CAPEX, and O&M costs, we aim to provide a comprehensive evaluation of FOW as an alternative energy source. Particular emphasis is placed on scenario-based estimates to account for uncertainties associated with this emerging technology. While FOW holds promise for reducing emissions and providing renewable energy, its economic feasibility is tempered by high costs and operational challenges. The analysis highlights these trade-offs to assess the potential of FOW within the context of Norway's energy landscape.

9.3.1 Production level

Project characteristics

This financial analysis is based on a FOW farm with the characteristics and additional parameters provided in Figure 9.2. As such, the analysis considers a total installed capacity of 300 MW, comprising 20 turbines, each with a capacity of 15 MW.

Wind Farm Characteristics	
Foundation	Floating
Electricity type	DC
Capacity (MW)	300
Numbers of turbine (15MW/turbine)	20
Distance to shore (km)	165
Water depth	125

Table 9.2: *FOWF characteristics*

Capacity factor

Based on the literature presented, we estimate capacity factors of 57.0% (advanced), 49.15% (base), and 48.75% (conservative) for the FOW farm, assumed to be located about 12 km from the Balder field. These estimates align with our reference literature, but it’s uncertain whether they might be slightly high in the Norwegian context, as we still lack extensive estimates for floating wind farms.

Total annual production volume

For FOW, no transmission loss is assumed, as the farm is located relatively close to the installation. As a result, the total annual production volume depends solely on the capacity factor, resulting in a base case production volume of 1,291,662 MWh. After 2050, when the electricity must be transported to the onshore grid, a transmission loss of 10% is expected, reducing the base case production volume to 1,162,496 MWh. The advanced and conservative estimates will follow the same calculation method, adjusted for their respective capacity factors.

Surplus gas volumes

This calculation follows the same method as for SMR but uses a different production volume, resulting in a total gas volume freed up for sale of 3,609,463 MWh. The much lower capacity factor for FOW results in the gas volume available for sale being just over half that of SMR. This directly impacts the revenue potential, making it substantially lower for FOW compared to SMR. To achieve comparable revenue streams for both technologies, the installed capacity for wind would need to be nearly doubled. This consideration will be explored further in the discussion section below.

Total emission savings

With the base case production volume for FOW at 1,291,662 MWh, the total CO_2 emissions avoided and thus exempt from taxes and quotas amount to 774,997 tons. By multiplying this figure by the assumed constant price of taxes and quotas, set at 2,410 NOK per ton in the base case, the total annual savings are approximately 1,868 million NOK.

9.3.2 Operational lifetime

Our reference literature generally indicates lifetimes for offshore wind farms between 20-30 years. These form the basis for our advanced and conservative scenarios, with 25 years as the base. Some studies suggest offshore turbines may have shorter lifetimes than onshore due to increased wear and tear caused by exposure to saltwater and harsher weather conditions (Business Norway, 2024). However, advancements in technology, potentially commercially available by 2030, suggest lifetimes of up to 50 years for the steel structures (Ferd, 2022). Considering both perspectives, and to ensure a more comprehensive and inclusive analysis, we have chosen to use a range for the lifetime rather than a single figure, as was done for SMR.

9.3.3 Construction time

The construction timeline for the FOW farm depends on the state of the technology by 2030 and the total MW to be installed. To estimate typical construction timelines, we reviewed data from completed and planned projects. The world's first floating wind farm, Hywind Scotland, took 3 years to complete. Hywind Tampen, by contrast, took six years to install 88 MW, though it experienced significant cost and time delays, partly due to COVID-19. Despite these delays, the project shortened the overall construction time compared to earlier benchmarks. Experts anticipate further reductions in costs and construction timelines by 2030 as the technology matures and more experience is gained.

The Goliat Vind project, targeting final investment decision in the second half of 2025, aims for completion by 2028, planning approximately three years for construction. However, this is a 75 MW farm, substantially smaller than the one assumed in this case. On the one hand, continued technological advancements by 2030 could further reduce construction times. On the other hand, the scale of a larger farm suggests longer construction timelines. While it wouldn't be accurate to simply multiply the construction time proportionally to the farm size, it is reasonable to expect a larger project to take more time to build. Overall, we find it appropriate to assume a base case construction time of 4 years, with 2 years as the advanced scenario and 6 years as the conservative.

9.3.4 CAPEX

The CAPEX figures in the financial analysis are based on estimates from BVG, NVE, and Martinez, adjusted for inflation. These adjustments result in an average 2030 CAPEX of NOK 14,770 million for a 300 MW FOW. However, since most studies project declining costs for FOW, a 10% learning curve has been applied to the averaged estimate for 2030, resulting in a final CAPEX estimate of NOK 12,925 million, used as the advanced scenario.

The Hywind Tampen project significantly exceeded its initial estimates, and for a wind farm of 300 MW, its inflation adjusted cost would be NOK 31.84 billion. While this estimate reflects substantial cost overruns and represents a FOAK project in Norway, we consider it overly optimistic to exclude this figure entirely. As the first offshore wind project completed in Norway, it remains the most relevant estimate given its technological similarity, recency, and geographical proximity. Consequently, we have chosen to incorporate this estimate into the final CAPEX calculation. The Tampen project demonstrated a 35% learning curve compared to the earlier Hywind Scotland project. Applying a similar learning curve to a 300

MW project from 2024 to 2030 results in an adjusted CAPEX of approximately NOK 20,509 million. This estimate will therefore represent our conservative scenario CAPEX.

To balance these perspectives, we in the base scenario assigned 70% weight to the Hywind Tampen estimate, reflecting a 35% learning curve, and a 30% weight to the average of BVG, NVE and Martinez estimate, reflecting a 10% learning curve. This approach yields a base case CAPEX of NOK 17,883 million.

The cost of cables and transmission is assumed to be the same as for the electrification of Balder using SMR. Accordingly, the estimated costs for the moderate, conservative, and advanced scenarios are NOK 2,478 million, NOK 3,238 million, and NOK 1,717 million, respectively, which is included in the total CAPEX presented above. An additional cable length is required to account for the distance between the oil platform and the FOWF. While the exact distance between the FOWF and the Balder field remains uncertain, we have based the calculation on the 12 km distance between the Hywind Tampen FOWF and the Gullfaks A platform. This results in additional cable costs of NOK 120 million for the base scenario, NOK 163 million for the conservative scenario, and NOK 76 million for the advanced scenario.

Furthermore, inter-array cables for the FOWF must also be considered. As detailed in the data section, these costs are calculated on a per MW basis. The inter-array cable costs are estimated at NOK 215 million for the base scenario, NOK 287 million for the conservative scenario, and NOK 143 million for the advanced scenario.

As mentioned, we arrive at a total CAPEX for a 300 MW wind farm of NOK 17,833 million in the base scenario. This estimate is slightly lower than the planned costs for Hywind Tampen, which were set at NOK 5.4 billion, equivalent to NOK 18.4 billion for a 300 MW project. Although cost reductions are expected as technology advances by 2030, achieving large-scale reductions within the timeframe is deemed unlikely. Additionally, inflation and scaling challenges must be considered. Consequently, we find our estimate to be a reasonable and realistic reflection of anticipated costs.

Scenario (NOKm)	Advanced	Base	Conservative
Turbine cost	4 994	6 849	7 644
Foundation and installation cost	5 412	7 423	8 285
Inter-array cables	143	215	287
FOW to oil platform	76	120	163
Transmission cost	1 717	2 478	3 239
Development cost	582	798	891
Total CAPEX	12 925	17 883	20 509

Table 9.3: *Final CAPEX assumptions, FOW*

9.3.5 O&M costs

The O&M costs for the 300 MW FOWF are projected through a scenario-based analysis. Under a base scenario, annual O&M costs are estimated at NOK 411 million, while a conservative scenario raises this estimate to NOK 504 million, reflecting potential challenges and inefficiencies. Conversely, an advanced scenario projects lower annual costs of NOK 399 million, highlighting the potential impact of technological advancements and operational optimizations.

It is crucial to acknowledge the inherent uncertainty in O&M cost estimation due to factors such as the varying lifetimes of critical components and their associated replacement costs. Additionally, the specific conditions of the North Sea, characterized by complex weather patterns, significant wave activity, and logistical accessibility, significantly influence cost projections. While these uncertainties are accounted for in the estimates, actual costs could deviate either higher or lower. Nonetheless, these projections represent the most likely annual costs in our analysis, balancing a comprehensive evaluation of potential risks and advancements.

9.4 Investment and cost analysis results

Before presenting our estimated models, it is important to clarify the purpose and scope of our analysis. This study models hypothetical FOW and SMR projects set several years in the future, a task inherently constrained by limited data and significant uncertainty surrounding technological, political, and economic developments. Given these factors, producing precise or definitive conclusions is not feasible. However, the analysis offers valuable high-level insights into the economic and financial aspects of both technologies, highlighting potential opportunities and challenges. As such, the results should be interpreted with a clear understanding of the analysis's exploratory and illustrative intent.

Figures 9.4 and 9.5 summarize the results of our financial and cost analysis. We assigned a 70% weight to the base scenario and 15% each to the advanced and conservative scenarios. The base scenario carries the highest weight as it represents the most likely outcome based on current data, while the other scenarios reflect potential deviations with lower probabilities. To account for uncertainties, we used broad intervals for input factors with highly variable estimates. Consequently, when these factors align on either extreme, the advanced and conservative estimates become highly optimistic or pessimistic. Therefore, we have given these scenarios less weight in our final LCOE and NPV figures.

Scenario	Weigth	NPV	Weigthed NPV	Final project NPV	LCOE	Final project LCEO
Advanced	15 %	61 215,85	9 182,38	**9 838,59**	801,91	**1 202,86**
Base	70 %	4 322,18	3 025,53		1 189,09	
Conservativ	15 %	-15 795,44	-2 369,32		1 668,08	

Table 9.4: *Summary of financial analysis, SMR*

Scenario	Weigth	NPV	Weigthed NPV	Final project NPV	LCOE	Final project LCEO
Advanced	15 %	48 429,21	7 264,38	**9 702,10**	836,27	**1 503,20**
Base	70 %	4 822,08	3 375,45		1 505,94	
Conservativ	15 %	-6 251,59	-937,74		2 157,32	

Table 9.5: *Summary of financial analysis, FOW*

Our DCF analysis for SMR yields a project NPV of NOK 9.84 billion and an associated LCOE of 1203 NOK/MWh. For FOW, the corresponding figures are NOK 9.70 billion and 1503 NOK/MWh. The detailed DCF and LCOE models are presented in the appendix.

10. Discussion

The purpose of this master's thesis is to contribute to the discussion on how Norway can meet the increasing demand for electricity while adhering to international commitments, such as the Paris Agreement and the European Green Deal. This thesis proposes that electrifying oil and gas installations on the Norwegian continental shelf could be a key solution. However, the approach to achieving this is highly debated, and this analysis aims to shed light on some of the potential alternatives. The thesis is organized into three main sections. First, it establishes the context by reviewing examining the technologies and markets for SMRs and FOW. Second, it explores the broader power and oil and gas markets, along with the rationale for why electrification is essential to meeting emission reduction targets. Finally, a financial analysis compares the feasibility of different solutions.

The government's strategy relies on FOW becoming cost competitive as a viable option for electrifying the Norwegian continental shelf. Electrification not only reduces emissions but also frees up power in the grid for other purposes, helping stabilize prices and enabling industries to remain in their regions rather than being displaced as demand increases. However, the findings of this thesis suggest that floating offshore wind may not be the only viable solution. Based on our financial analysis, SMRs demonstrate a lower LCOE, highlighting the need to compare the two technologies on aspects beyond financial performance alone.

10.1 Comparative analysis of SMR and FOW

This section focuses on discussing and comparing the results of our financial analysis, as comparing the two technologies is necessary to provide a more comprehensive answer to our research question. While this is a master's thesis in finance, and the financial analysis is the primary focus, including a brief discussion of additional considerations provides a more well-rounded comparison of the energy sources. Therefore, we will touch on non-financial aspects such as emissions, land use, and safety to offer a broader perspective, while keeping the discussion concise given the scope of this thesis.

10.1.1 Financial comparison

The results from our investment analysis indicate that the NPV figures for both technologies are relatively similar. While we have been conservative in our estimates for both, we would argue that we have applied additional caution to the SMR figures, considering that it would represent Norway's first nuclear reactor. However, given the significant uncertainties surrounding future revenue streams, particularly long-term power and gas price projections, we believe less emphasis should be placed on the investment analysis results. Revenue stabilization, for instance through government-guaranteed pricing or signing PPAs with offtakers, could increase the relevance of this analysis. However, the results are included to demonstrate that, according to our analysis, both SMR and FOW investments can be profitable without government subsidies.

The LCOE offers a more robust basis for comparison, both within this analysis and with external studies on energy technologies. For SMRs, our LCOE estimates range from 802 to 1,668 NOK/MWh, which is slightly higher than figures from sources like the Swedish memorandum and NREL. However, they fall below NVE's estimate, which has a median of 1,600 NOK/MWh. Notably, NVE's figures are based on a 1,600 MW conventional reactor and reflect cautious assumptions, including a 40-year operational lifetime.

For FOW, the LCOE is estimated to range from 836 to 2,157 NOK/MWh, with a weighted average of 1503 NOK/MWh. This aligns closely with NVE's base-case estimate of 1540 NOK/MWh. Other estimates, such as those from NREL and Martinez, are slightly higher at 1,730 and 1,616 NOK/MWh, respectively. Overall, we consider this financial analysis a reasonable representation of both technologies within the context of electrifying the Norwegian continental shelf. The results indicate that SMRs may offer a more cost-effective solution due to their lower LCOE compared to FOW.

Financing cost considerations

A critical discussion point in the financial analysis is how the discount rate significantly impacts the valuation of the projects. As noted earlier, the final discount rate is influenced by the cost at which banks are willing to lend, which depends on several factors. For instance, if the borrower is a large oil producer such as Vår Energi or Equinor, the cost of debt could be relatively low due to their size and financial strength. Conversely, smaller or less established entities may face significantly higher borrowing costs, as the borrower’s profile largely determines the cost of debt.

Additionally, debt financing could become considerably cheaper if the government intervenes to support financing and help lower the cost of capital. To illustrate this, Table 10.1 demonstrates the impact of adjusting the assumed WACC by 1 percentage point in either direction. As shown, even a modest 1% increase significantly worsens the financial viability of the projects in terms of LCOE.

Scenarios	(-)1%	Applied WACC	(+)1%
SMR, NOK/MWh	1,052	1,203	1,365
FOW, NOK/MWh	1,385	1,503	1,628

Table 10.1: *Sensitivity table, WACC*

This underscores the critical importance of minimizing financing costs for the success of alternative power projects like these. Therefore, if the government and oil producers are committed to achieving the electrification of oil and gas installations, they would likely need to take active measures to ensure the financial feasibility of such initiatives.

Operational lifetime implications

The financial analysis assumes an operational lifetime of 25 years for FOW and 60 years for SMR in the base case scenario. This assumption does not account for major reinvestments to extend the expected lifetime of either technology. However, one could argue that to truly compare the two technologies, it would be necessary to either assume significant reinvestment in the wind farm to extend its lifetime or include an additional investment similar in scale to the initial one. This would align the revenue cash flows of the two projects more closely.

While the cash flows from SMR projects far into the future have low NPVs due to the high discount rate, their nominal values remain substantial. However, we have chosen not to include reinvestments for FOW in our analysis, as the focus of this thesis is on electrifying oil and gas installations. The assumed lifetime for the reference field extends only until 2050, making it less relevant to extend the FOW's lifetime by an additional 25 years, as the significant revenues from carbon tax savings would no longer be applicable. If a lifetime extension for the installation were assumed, reinvestments in FOW would become a more relevant consideration.

This highlights an advantage of SMRs over FOW. A major reinvestment in FOW to extend its lifetime, especially if assumed to occur today which increases its NPV, would make the FOW alternative much more expensive. By excluding this possibility from our analysis, we may underestimate the cost advantage of SMRs, as the large cost difference that would arise from this scenario is not reflected.

General viability in the Norwegian energy mix

It is important to note that this conclusion is valid only in the specific context of electrifying oil and gas installations. When you remove the aspects related to the specific context, notably the revenues from gas sales and the savings of carbon taxes and quotas, the financial outlook changes significantly. This is evident in the DCF models presented in the appendix, where the projections for the period after 2050 resemble those of SMR plants and FOWFs operating without the electrification aspect.

For FOW, the net income turns negative once the oil installation is decommissioned, as this directly eliminates the cost savings from reduced carbon taxes. With an electricity price of 590 NOK/MWh and the given cost inputs, selling power from the OWF to the grid alone would not be profitable. A relevant discussion could be whether shutting down the platform entirely would be more advantageous than continuing operations at a loss. However, due to the significant uncertainties surrounding future revenues, this assumption has not been made in this analysis.

For SMRs, the net income remains slightly positive after the decommissioning of the oil installation but is significantly lower than the levels observed before 2050. Worth noting is that the CAPEX, and subsequently the depreciation expense, is higher in our model than it would be in practice, as it assumes the electricity needs to be transported 165 km to the installation. If instead the electricity were transported directly to the grid, much of the cable and transmission infrastructure would not be needed, making the net income figures slightly better. However, even with this adjustment, the NPV would still not be positive. While the purpose of this thesis is not to assess the suitability of SMRs or FOW for broader implementation in Norway's energy mix, the analysis suggests that further research is necessary before considering SMRs or FOW as viable options for general energy production in Norway.

10.1.2 Emissions and Renewable Classification

Both technologies emit very low levels of greenhouse gases, with nuclear reactors emitting 6 tons of CO_2 per GWh and wind power 11 tons per GWh (Ritchie, 2020). While the difference in emissions between nuclear and wind is small, especially compared to oil's 720 tons per GWh, the potential emission reduction for FOW is significantly limited in this case due to its lower production capacity. With its low capacity factor, FOW can only supply half of the platform's 300 MW power requirement, leaving the remaining 50% of the demand unresolved.

Although this challenge also exists with nuclear, it is more significant for FOW due to its lower production capacity. The remaining power demand would need to be met either by burning gas or through transmission lines connecting to the grid.

Historically, obtaining grid connection licenses for large oil installations has been difficult. Continuing to burn gas, however, undermines the goal of reducing emissions and contradicts the purpose of electrification. One could argue that covering half the demand with FOW might increase the likelihood of securing a grid connection license, but this outcome remains uncertain. This highlights a key disadvantage of FOW compared to SMRs. With similar installed capacity, FOW delivers less power, reducing cost savings and revenues. For oil companies deciding between these technologies, the lower power output from FOW makes it less attractive for maximizing economic and operational benefits.

One potential advantage of FOW is that, unlike nuclear energy, it is classified as renewable. This is because while FOW draws on naturally replenishing sources, SMRs depend on non-renewable inputs like uranium. Although this classification does not directly impact nuclear energy’s ability to reduce emissions, it may have indirect consequences. Government subsidies and green financing programs often prioritize renewable technologies, which could make nuclear projects harder or more expensive to finance. International policies like the European Green Deal also heavily emphasize renewable energy, potentially limiting nuclear energy’s role in future green initiatives.

In the context of electrifying the Norwegian continental shelf, these factors could affect the strategic and economic viability of SMRs compared to FOW. While the financial analysis suggests that SMRs could be profitable even without subsidies, the availability of subsidies for FOW might shift the balance in its favor, particularly given the uncertainties in the estimates. Although both technologies help reduce emissions and lower costs associated with carbon taxes, FOW benefits from being classified as a fully renewable energy source, which could make it more politically and socially favorable in the long term.

10.1.3 Land use and safety concerns

There are several additional aspects to consider when comparing the two technologies. Two important factors worth highlighting are land use and its impact on local communities and biodiversity, as well as safety.

In terms of land use, both technologies are relatively efficient compared to other energy sources. SMRs require much less space than conventional nuclear plants due to their compact design, making them suitable for integration into existing industrial areas. FOW avoids land use entirely, as turbines are located offshore, but it does raise concerns about its potential impact on marine biodiversity. Despite these differences, both technologies score highly in terms of efficient land use compared to other energy sources (Ritchie, 2022).

Safety is another key consideration. Nuclear energy, while often perceived as dangerous, is statistically one of the safest energy sources. High-profile incidents such as Chernobyl in 1986 and Fukushima in 2011 have contributed to the fear surrounding nuclear power (Cordina, 2025). However, data indicates that conventional nuclear plants are the second safest energy source, measured by deaths per GWh, with solar ranking first and wind coming in third (Ritchie, 2020). Additionally, SMRs build on the operational experience of traditional reactors while incorporating advanced safety features, making them arguably even safer than what these studies suggest. Their passive safety systems, simpler designs, and natural cooling mechanisms allow them to manage incidents with minimal or no operator intervention, significantly reducing risks (European Commission, 2024).

Some would argue that public perception, particularly within the government, remains a significant barrier to the adoption of nuclear energy. While SMRs offer notable safety advancements, the lingering fear of nuclear accidents continues to influence opinions. However, recent trends suggest this perception may be shifting. According to studies by Ipsos, nuclear energy is now the favored energy source among Norwegians, ranked even higher than hydropower. In contrast, wind energy has faced declining public support in recent years, partly due to strong local opposition to onshore wind farms (Ipsos, 2023). While both technologies are considered safe, the advanced safety features of SMRs, combined with their already lower fatality rate, suggest they are slightly superior to wind in terms of safety.

11. Conclusion

Are Small Modular Reactors or Floating Offshore Wind financially viable alternatives for electrifying oil and gas installations on the Norwegian continental shelf?

To meet emission reduction targets outlined in domestic legislation and international climate agreements, the Norwegian government is prioritizing electrification as a key strategy for achieving significant emission reductions. The oil and gas sector is a major contributor to Norway's total greenhouse gas emissions, and in response, numerous platforms and fields have already undergone partial or full electrification. However, the current power grid does not have the capacity to support many of the largest installations, which are often among the most polluting. This limitation creates an urgent need for alternative energy sources that can bridge the gap and ensure sufficient electricity supply to the installations.

This analysis indicates that SMRs are the more cost-effective option, with a median LCOE of NOK 1,203/MWh compared to NOK 1,503/MWh for FOW. With 300 MW of installed capacity, both technologies could be profitable investments even without government subsidies. This suggests that both SMRs and FOW are financially viable options for electrifying the Norwegian continental shelf. However, this conclusion is specific to the context of electrifying oil and gas installations and should not be taken as evidence for incorporating these technologies into the general Norwegian energy mix. A more comprehensive analysis, excluding the unique considerations of oil and gas installations, would be required to support such a broader application.

When considering factors such as emissions, safety, and land use, nuclear energy shows a slight advantage over FOW. The most significant difference, however, is the substantially higher production capacity and consequently greater revenue potential of SMRs compared to FOW. While the cost estimates are uncertain and represent averages from wide intervals, this analysis shows that SMRs perform better financially and across other key factors. Nevertheless, both SMRs and FOWFs offer significant financial viability and deserve to be considered as part of Norway's future energy strategy for electrifying oil and gas installations.

Declaration on the use of AI tools in the work on this master's thesis

Name (and version) of the AI tool: ChatGPT 4.0

Purpose of using the tool: Language enhancement

We are aware that we are responsible for all content of this master's thesis, including the parts where AI tools are used. We are responsible for ensuring that the thesis complies with ethical rules for privacy and publication.

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Appendix

SMR - Base Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Small Modular Reactors

(In Million NOK) Year	0	1	2	3	4	5	6	7	20	21	64
	2030	2031	2032	2033	2034	2035	2036	2037	2050	2051	2095
Income / Cost Savings							5261,5	5261,5	5261,5	1395,5	1395,5
Natural gas	0,0	0,0	0,0	0,0	0,0	0,0	2 183,4	2 183,4	2 183,4		
Price (NOK / MWh)	359,0	359,0	359,0	359,0	359,0	359,0	359,0	359,0	359,0		
Volume (MWh)	0	0	0	0	0	0	6 081 943	6 081 943	6 081 943		
Carbon Quotas & Taxes	0,0	0,0	0,0	0,0	0,0	0,0	3 078,1	3 078,1	3 078,1		
Norwegian Carbon Taxes (NOK/ tCO2)	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0		
Volume (tCO2)	0,0	0,0	0,0	0,0	0,0	0,0	1 277 208,0	1 277 208,0	1 277 208,0		
Electricity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1395,5	1395,5
Price (NOK / MWh)	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0
Volume (MWh)	0	0	0	0	0	0	0	0	0	2 365 200	2 365 200
Costs							2 063,5	1 189,7	1 189,7	1 166,6	1 166,6
Operational Costs							1 555,0	681,2	681,2	681,2	681,2
Fuel Costs	0,0	0,0	0,0	0,0	0,0	0,0	968,4	94,6	94,6	94,6	94,6
Fuel Price (NOK / MWh)	40,0	40,0	40,0	40,0	40,0	40,0	40,0	40,0	40,0	40,0	40,0
Volume (MWh)	0	0	0	0	0	0	2 365 200	2 365 200	2 365 200	2 365 200	2 365 200
First Refueling							873,8				
Waste disposal	0,0	0,0	0,0	0,0	0,0	0,0	141,9	141,9	141,9	141,9	141,9
Waste disposal cost (NOK / MWh)	60,0	60,0	60,0	60,0	60,0	60,0	60,0	60,0	60,0	60,0	60,0
Volume (MWh)	0	0	0	0	0		2 365 200	2 365 200	2 365 200	2 365 200	2 365 200
Fixed O&M	188,0	188,0	188,0	188,0	0,0	0,0	444,7	444,7	444,7	444,7	444,7
Cost (NOK / MWh)	188,0	188,0	188,0	188,0	188,0	188,0	188,0	188,0	188,0	188,0	188,0
Volume (MWh)	0,0	0,0	0,0	0,0	0,0	0,0	2 365 200,0	2 365 200,0	2 365 200,0	2 365 200,0	2 365 200,0
Additional Costs		0,0	0,0	0,0	0,0	0,0	508,5	508,5	508,5	485,4	485,4
Gas Transport Tariff	0,0	0,0	0,0	0,0	0,0	0,0	23,12	23,12	23,12		
Depriciation							485,4	485,4	485,4	485,4	485,4
EBIT							3 198,0	4 071,8	4 071,8	228,9	228,9
Tax (22%)							703,6	895,8	895,8	50,3	50,3
Net Income after Taxes							2 494,4	3 176,0	3 176,0	178,5	178,5
Depriciation							485,4	485,4	485,4	485,4	485,4
CAPEX	2 647,8	5 295,6	5 295,6	5 295,6	5 295,6	5 295,6					
Development cost	2 647,8	0,0	0,0	0,0	0,0	0,0					
Overnight Capital Costs		4 800,0	4 800,0	4 800,0	4 800,0	4 800,0					
Cables and Transmission		495,6	495,6	495,6	495,6	495,6					
Free Cash Flow (FCF)	-2 647,8	-5 295,6	-5 295,6	-5 295,6	-5 295,6	-5 295,6	2 979,9	3 661,4	3 661,4	663,9	663,9
Accumulated FCF	-2 647,8	-7 943,4	-13 239,0	-18 534,6	-23 830,3	-29 125,9	-26 146,0	-22 484,6	25 113,7	25 777,6	54 991,1
Discount Factor	100%	94,34%	89,00%	83,96%	79,21%	74,73%	70,50%	66,51%	31,18%	29,42%	2,27%
Discounted Cash Flow	-2 647,8	-4 995,9	-4 713,1	-4 446,3	-4 194,6	-3 957,2	2 100,7	2 435,0	1 141,6	195,3	15,0

WACC	6,00%
NPV	4 322,2

SMR - Advanced Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Small Modular Reactors

Year (In Million NOK)	0	1	2	3	4	5	20	21	63
	2030	2031	2032	2033	2034	2035	2050	2051	2093
Income / Cost Savings					8005,7	8306,6	14437,0	1955,2	1955,2
Natural gas	0,0	0,0	0,0	0,0	3 010,4	3 010,4	3 010,4		
Price (NOK / MWh)	479,0	479,0	479,0	479,0	479,0	479,0	479,0		
Volume (MWh)	0	0	0	0	6 284 674	6 284 674	6 284 674		
Carbon Quotas & Taxes	0,0	0,0	0,0	0,0	4 995,4	5 296,3	11 426,7		
Norwegian Carbon Taxes (NOK/ tCO2)	2 997,0	3 177,0	3 368,0	3 571,0	3 785,0	4 013,0	8 658,0		
Volume (tCO2)	0,0	0,0	0,0	0,0	1 319 781,6	1 319 781,6	1 319 781,6		
Electricity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1 955,2	1 955,2
Price (NOK / MWh)	800,0	800,0	800,0	800,0	800,0	800,0	800,0	800,0	800,0
Volume (MWh)	0	0	0	0	0	0		2 444 040	2 444 040
Costs					1 697,6	948,0	924,8	924,8	924,8
Operational Costs					1 258,0	508,4	508,4	508,4	508,4
Fuel Costs	0,0	0,0	0,0	0,0	823,0	73,3	73,3	73,3	73,3
Fuel Price (NOK / MWh)	30,0	30,0	30,0	30,0	30,0	30,0	30,0	30,0	30,0
Volume (MWh)	0	0	0	0	2 444 040	2 444 040	2 444 040	2 444 040	2 444 040
First Refueling					749,7				
Waste disposal	0,0	0,0	0,0	0,0	110,0	110,0	110,0	110,0	110,0
Waste disposal cost (NOK / MWh)	45,0	45,0	45,0	45,0	45,0	45,0	45,0	45,0	45,0
Volume (MWh)	0	0	0	0	2 444 040	2 444 040	2 444 040	2 444 040	2 444 040
Fixed O&M	0,0	0,0	0,0	0,0	325,1	325,1	325,1	325,1	325,1
Cost (NOK / MWh)	133,0	133,0	133,0	133,0	133,0	133,0	133,0	133,0	133,0
Volume (MWh)	0,0	0,0	0,0	0,0	2 444 040,0	2 444 040,0	2 444 040,0	2 444 040,0	2 444 040,0
Additional Costs		0,0	0,0	0,0	439,6	439,6	416,5	416,5	416,5
Gas Transport Tariff	0,0	0,0	0,0	0,0	23,12	23,12			
Depriciation					416,5	416,5	416,5	416,5	416,5
EBIT					6 308,1	7 358,7	13 512,2	1 030,4	1 030,4
Tax (22%)					1 387,8	1 618,9	2 972,7	226,7	226,7
Net Income after Taxes					4 920,3	5 739,8	10539,5	803,7	803,7
Depriciation					416,5	416,5	416,5	416,5	416,5
CAPEX	2 271,7	7 572,4	7 572,4	7 572,4					
Development cost	2 271,7	0,0	0,0	0,0					
Overnight Capital Costs		7 000,0	7 000,0	7 000,0					
Cables and Transmission		572,4	572,4	572,4					
Free Cash Flow (FCF)	-2 271,7	-7 572,4	-7 572,4	-7 572,4	5 336,8	6 156,3	10 956,0	1 220,2	1 220,2
Accumulated FCF	-2 271,7	-9 844,1	-17 416,5	-24 989,0	-19 652,2	-13 495,9	114 193,4	115 413,6	166 661,4
Discount Factor	100%	95,24%	90,70%	86,38%	82,27%	78,35%	37,69%	35,89%	4,62%
Discounted Cash Flow	-2 271,7	-7 211,8	-6 868,4	-6 541,3	4 390,6	4 823,6	4 129,2	438,0	56,4

WACC	5,00%
NPV	61 229,8

SMR - Conservative Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Small Modular Reactors

Year

(In Million NOK)	0	1	2	3	4	5	6	7	8	20	21	67
	2030	2031	2032	2033	2034	2035	2036	2037	2038	2050	2051	2097
Income / Cost Savings									2819,2	3675,1	982,3	982,3
Natural gas	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1 437,4	1 437,4		
Price (NOK / MWh)	239,0	239,0	239,0	239,0	239,0	239,0	239,0	239,0	239,0	239,0		
Volume (MWh)	0	0	0	0	0	0	0	0	6 014 366	6 014 366		
Carbon Quotas & Taxes	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1 381,7	2 237,7		
Norwegian Carbon Taxes (NOK/ tCO2)	800,0	832,0	865,0	900,0	936,0	973,0	1 012,0	1 052,0	1 094,0	1 752,0		
Volume (tCO2)	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1 263 016,8	1 277 208,0		
Electricity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	982,3	982,3
Price (NOK / MWh)	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0
Volume (MWh)	0	0	0	0	0	0	0	0	0	0	2 338 920	2 338 920
Costs									2 384,6	1 389,0	1 389,0	1 365,9
Operational Costs									1 807,2	811,5	811,5	811,5
Fuel Costs	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	1 114,8	116,9	116,9	116,9
Fuel Price (NOK / MWh)	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0
Volume (MWh)	0	0	0	0	0	0	0	0	2 338 920	2 338 920	2 338 920	2 338 920
First Refueling									997,9			
Waste disposal	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	201,1	203,4	203,4	203,4
Waste disposal cost (NOK / MWh)	86,0	86,0	86,0	86,0	86,0	86,0	86,0	86,0	86,0	86,0	86,0	86,0
Volume (MWh)	0	0	0	0	0	0	0	0	2 338 920	2 365 200	2 365 200	2 365 200
Fixed O&M	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	491,2	491,2	491,2	491,2
Cost (NOK / MWh)	210,0	210,0	210,0	210,0	210,0	210,0	210,0	210,0	210,0	210,0	210,0	210,0
Volume (MWh)	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	2 338 920,0	2 338 920,0	2 338 920,0	2 338 920,0
Additional Costs		0,0	0,0	0,0	0,0	0,0	0,0	0,0	577,5	577,5	577,5	554,4
Gas Transport Tariff	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	23,12	23,12	23,12	
Depriciation									554,4	554,4	554,4	554,4
EBIT									434,5	2 286,1	-406,7	-383,6
Tax (22%)									95,6	502,9	-89,5	-84,4
Net Income after Taxes									338,9	1 783,1	-317,2	-299,2
Depriciation									554,4	554,4	554,4	554,4
CAPEX	3 023,9	4 319,8	4 319,8	4 319,8	4 319,8	4 319,8	4 319,8	4 319,8				
Development cost	3 023,9	0,0	0,0	0,0	0,0	0,0	0,0	0,0				
Overnight Capital Costs		3 857,1	3 857,1	3 857,1	3 857,1	3 857,1	3 857,1	3 857,1				
Cables and Transmission		462,7	462,7	462,7	462,7	462,7	462,7	462,7				
Free Cash Flow (FCF)	-3 023,9	-4 319,8	-4 319,8	-4 319,8	-4 319,8	-4 319,8	-4 319,8	-4 319,8	893,3	2 337,5	237,2	255,2
Accumulated FCF	-3 023,9	-7 343,7	-11 663,6	-15 983,4	-20 303,3	-24 623,1	-28 942,9	-33 262,8	-32 369,5	-8 225,4	-7 988,2	3 733,1
Discount Factor	100%	93,46%	87,34%	81,63%	76,29%	71,30%	66,63%	62,27%	58,20%	25,84%	24,15%	1,07%
Discounted Cash Flow	-3 023,9	-4 037,2	-3 773,1	-3 526,3	-3 295,6	-3 080,0	-2 878,5	-2 690,2	519,9	604,1	57,3	2,7

WACC	7,00%
NPV	-15 795,4

FOW - Base Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Floating Offshore Wind

(In Million NOK)	Year 0	1	2	3	4	5	20	21	28
	2030	2031	2032	2033	2034	2035	2050	2051	2058
Income / Cost Savings					3192,6	3192,6	3192,6	685,9	685,9
Natural gas	0,0	0,0	0,0	0,0	1 324,9	1 324,9	1 324,9		
Price (NOK / MWh)	359,0	359,0	359,0	359,0	359,0	359,0	359,0		
Volume (MWh)	0	0	0	0	3 690 463	3 690 463	3 690 463		
Carbon Quotas & Taxes	0,0	0,0	0,0	0,0	1 867,7	1 867,7	1 867,7		
Norwegian Carbon Taxes (NOK/ tCO2)	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0	2 410,0		
Volume (tCO2)	0,0	0,0	0,0	0,0	774 997,2	774 997,2	774 997,2		
Electricity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	685,9	685,9
Price (NOK / MWh)	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0	590,0
Volume (MWh)	0	0	0	0	0	0		1 162 496	1 162 496
Costs					1 170,4	1 170,4	1 156,3	1 156,3	1 156,3
Operational Costs					441,0	441,0	441,0	441,0	441,0
O&M	0,0	0,0	0,0	0,0	441,0	441,0	441,0	441,0	441,0
Additional Costs		0,0	0,0	0,0	729,4	729,4	715,3	715,3	715,3
Gas Transport Tariff	0,0	0,0	0,0	0,0	14,03	14,03			
Depriciation					715,3	715,3	715,3	715,3	715,3
EBIT					2 022,3	2 022,3	2 036,3	-470,5	-470,5
Tax (22%)					444,9	444,9	448,0	-103,5	-103,5
Net Income after Taxes					1 577,4	1 577,4	1588,3	-367,0	-367,0
Depriciation					715,3	715,3	715,3	715,3	715,3
CAPEX	798,2	5 695,0	5 695,0	5 695,0					
Development cost	798,2	0,0	0,0	0,0					
Turbine costs		2 283,1	2 283,1	2 283,1					
Foundation and installation		2 474,4	2 474,4	2 474,4					
Cables and transmission		826,0	826,0	826,0					
Inter-array cables		71,7	71,7	71,7					
Cables from OWF to oil platform		39,9	39,9	39,9					
Free Cash Flow (FCF)	-798,2	-5 695,0	-5 695,0	-5 695,0	2 292,7	2 292,7	2 303,6	348,4	348,4
Accumulated FCF	-798,2	-6 493,2	-12 188,3	-17 883,3	-15 590,6	-13 297,9	21 114,4	21 462,8	23 901,4
Discount Factor	100%	94,34%	89,00%	83,96%	79,21%	74,73%	31,18%	29,42%	19,56%
Discounted Cash Flow	-798,2	-5 372,7	-5 068,6	-4 781,7	1 816,0	1 713,2	718,3	102,5	68,2

WACC	6,00%
NPV	4 829,1

FOW - Advanced Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Floating Offshore Wind

	Year						
(In Million NOK)	0	1	2	3	20	21	31
	2030	2031	2032	2033	2050	2051	2061
Income / Cost Savings			5077,1	5259,6	9831,7	1078,5	1078,5
Natural gas	0,0	0,0	2 050,1	2 050,1	2 050,1		
Price (NOK / MWh)	479,0	479,0	479,0	479,0	479,0		
Volume (MWh)	0	0	4 279 886	4 279 886	4 279 886		
Carbon Quotas & Taxes	0,0	0,0	3 027,1	3 209,5	7 781,6		
Norwegian Carbon Taxes (NOK/ tCO2)	2 997,0	3 177,0	3 368,0	3 571,0	8 658,0		
Volume (tCO2)	0,0	0,0	898 776,0	898 776,0	898 776,0		
Electricity	0,0	0,0	0,0	0,0	0,0	1 078,5	1 078,5
Price (NOK / MWh)	800,0	800,0	800,0	800,0	800,0	800,0	800,0
Volume (MWh)	0	0	0	0		1 348 164	1 348 164
Costs			843,9	843,9	829,8	829,8	829,8
Operational Costs			399,0	399,0	399,0	399,0	399,0
O&M	0,0	0,0	399,0	399,0	399,0	399,0	399,0
Additional Costs		0,0	444,9	444,9	430,8	430,8	430,8
Gas Transport Tariff	0,0	0,0	14,03	14,03			
Depriciation			430,8	430,8	430,8	430,8	430,8
EBIT			4 233,3	4 415,7	9 001,8	248,7	248,7
Tax (22%)			931,3	971,5	1 980,4	54,7	54,7
Net Income after Taxes			3 302,0	3 444,3	7021,4	194,0	194,0
Depriciation			430,8	430,8	430,8	430,8	430,8
CAPEX	582,0	12 342,8					
Development cost	582,0	0,0					
Turbine costs		4 993,7					
Foundation and installation		5 412,3					
Cables and transmission		1 717,2					
Inter-array cables		143,3					
Cables from OWF to oil platform		76,3					
Free Cash Flow (FCF)	-582,0	-12 342,8	3 732,8	3 875,1	7 452,3	624,8	624,8
Accumulated FCF	-582,0	-12 924,8	-9 192,0	-5 316,9	89 757,3	90 382,1	96 630,3
Discount Factor	100%	95,24%	90,70%	86,38%	37,69%	35,89%	22,04%
Discounted Cash Flow	-582,0	-11 755,1	3 385,8	3 347,5	2 808,7	224,3	137,7

WACC	5,00%
NPV	48 447,0

FOW - Conservative Scenario

Cash Flow Analysis: Discounted Free Cash Flow

Floating Offshore Wind

Year	0	1	2	3	4	5	6	7	20	21	25
(In Million NOK)	2030	2031	2032	2033	2034	2035	2036	2037	2050	2051	2055
Income / Cost Savings							2092,0	2122,8	2660,8	484,3	484,3
Natural gas	0,0	0,0	0,0	0,0	0,0	0,0	1 314,1	1 314,1	1 314,1		
Price (NOK / MWh)	239,0	359,0	359,0	359,0	359,0	359,0	359,0	359,0	359,0		
Volume (MWh)	0	0	0	0	0	0	3 660 429	3 660 429	3 660 429		
Carbon Quotas & Taxes	0,0	0,0	0,0	0,0	0,0	0,0	777,9	808,7	1 346,7		
Norwegian Carbon Taxes (NOK/ tCO2)	800,0	832,0	865,0	900,0	936,0	973,0	1 012,0	1 052,0	1 752,0		
Volume (tCO2)	0,0	0,0	0,0	0,0	0,0	0,0	768 690,0	768 690,0	768 690,0		
Electricity	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	484,3	484,3
Price (NOK / MWh)	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0	420,0
Volume (MWh)	0	0	0	0	0	0	0	0	0	1 153 035	1 153 035
Costs							1 543,5	1 543,5	1 543,5	1 529,4	1 529,4
Operational Costs							504,0	504,0	504,0	504,0	504,0
O&M	0,0	0,0	0,0	0,0	0,0	0,0	504,0	504,0	504,0	504,0	504,0
Additional Costs		0,0	0,0	0,0	0,0	0,0	1 039,5	1 039,5	1 039,5	1 025,4	1 025,4
Gas Transport Tariff	0,0	0,0	0,0	0,0	0,0	0,0	14,03	14,03	14,03		
Depriciation							1 025,4	1 025,4	1 025,4	1 025,4	1 025,4
EBIT							548,5	579,3	1 117,4	-1 045,2	-1 045,2
Tax (22%)							120,7	127,4	245,8	-229,9	-229,9
Net Income after Taxes							427,9	451,8	871,5	-815,2	-815,2
Depriciation							1 025,4	1 025,4	1 025,4	1 025,4	1 025,4
CAPEX	890,9	3 923,6	3 923,6	3 923,6	3 923,6	3 923,6					
Development cost	890,9	0,0	0,0	0,0	0,0	0,0					
Turbine costs		1 528,9	1 528,9	1 528,9	1 528,9	1 528,9					
Foundation and installation		1 657,0	1 657,0	1 657,0	1 657,0	1 657,0					
Cables and transmission		647,8	647,8	647,8	647,8	647,8					
Inter-array cables		57,3	57,3	57,3	57,3	57,3					
Cables from OWF to oil platform		32,6	32,6	32,6	32,6	32,6					
Free Cash Flow (FCF)	-890,9	-3 923,6	-3 923,6	-3 923,6	-3 923,6	-3 923,6	1 453,3	1 477,3	1 897,0	210,2	210,2
Accumulated FCF	-890,9	-4 814,5	-8 738,1	-12 661,7	-16 585,3	-20 508,9	-19 055,6	-17 578,3	4 337,1	4 547,4	5 388,2
Discount Factor	100%	93,46%	87,34%	81,63%	76,29%	71,30%	66,63%	62,27%	25,84%	24,15%	18,42%
Discounted Cash Flow	-890,9	-3 666,9	-3 427,0	-3 202,8	-2 993,3	-2 797,5	968,4	920,0	490,2	50,8	38,7

WACC	7,00%
NPV	-6 251,6