Assessing Uncertainty in Offshore Wind Business Models with Hydrogen Integration

Does hydrogen integration make offshore wind more certain?

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by

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Summary

The transition to a low carbon energy system is focusing attention on the synergies between large scale offshore wind and green hydrogen production. These synergies can have system-wide benefits for the integration of wind farms to the power system, whilst improving their economic performance. Offshore wind investments face multiple uncertainties: commodity prices fluctuate and impact turbine cost, vessel rates required to install the turbines are dynamic and the electricity price fluctuates daily. Additionally, to realize wind-hydrogen synergies (hybrid powerplants) the electrolyzer is an additional source of cost uncertainty. On the contrary, the revenue uncertainty of the wind farm is expected to be mitigated through the use of Hydrogen Purchase Agreements. To take informed investment decisions regarding wind-hydrogen synergies, Vattenfall, a leading European utility, is interested in analyzing the trade-off between increased cost uncertainty and reduced revenue uncertainty.

This thesis investigates how integrating a 400 MW onshore electrolyzer with a 2 GW bottom-fixed wind farm affects the project's economic uncertainty. To answer the question, a three-step methodology is applied. Firstly, the economics of the offshore wind farm and hybrid powerplant are modelled without the presence of uncertainty, using Vattenfall's techno-economic model. This model considers investment and operation costs, along with the revenues of the wind farm from electricity sales on the power market. For the revenues of the hybrid powerplant, an optimization algorithm deciding when it is optimal to produce hydrogen or electricity is employed. Secondly, the uncertainties in key commodities (steel, aluminum, copper and shipping fuel oil), vessel day-rates, electricity prices and electrolyzer costs, are defined. Thirdly, the uncertainties are sampled through a Monte Carlo simulation to create 10,000 different realizations of the project, covering the entire range of possible outcomes. By combining the techno-economic model, the dispatch algorithm and the Monte Carlo approach, the uncertainties of the offshore farm and hybrid powerplant can be quantified, and their impact on the project economics can be evaluated.

The methodology allows to compare the effect of hydrogen integration in the business case uncertainty of an offshore wind farm. On a deterministic comparison, the two projects perform similarly. For the considered wind farm, the inclusion of the electrolyzer adds an additional € 94 M in cost uncertainty, while it reduces revenue uncertainty by € 18 M. These results hold true for the considered offshore farm, given projected conditions and modelling assumptions. For this case, the offshore wind farm is marginally more certain in terms of economic returns. Given the two projects produce similar investment returns, accepting the increased uncertainty of the hybrid powerplant is non-economical.

The results of the thesis do not favor an investment in hybrid project in terms of uncertainties. However, this result is true for the project investigated and as conditions change and hydrogen technology matures, the analysis can shift in favor of hydrogen. Specifically, hydrogen is a large scale infrastructure with the first full scale projects currently under development. With more project-experience gained, the uncertainty in costs can be reduced, favoring the hybrid projects. With increased support for large scale hydrogen production, the proposed framework for continuous analysis can be leveraged to keep pace with the external macroeconomic changes. The methodology can be extended and applied to other hybrid solutions, such as hybrid projects with batteries.

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1 Introduction

1.1. Renewable Energy

1.1.1. Wind Energy

Traditionally, fossil fuels were the main means of electricity generation, but in the last decade their share has been declining, as a consequence of the energy transition to more sustainable energy sources. Interestingly, in the first-half of 2024 more than 50% of electricity in Europe was generated through renewable sources [78]. In the context of the energy transition and independence, governments in Europe are manifesting a green transition away from fossil fuels, aiming for electrification of various sectors. This increased demand will be covered by renewable sources. Therefore, to meet the expected increase in electricity rapid capacity expansion of renewables has to be achieved.

Wind energy is one of the most widely deployed renewable generation technologies. In Europe the total installed wind power doubled between 2015 and 2024, amounting to 285 GW in 2024, as seen in Figure 1.1. This development has been stimulated by a wide range of political and financial support schemes and historically low interest rates. Despite the significant growth of wind energy, more is required to meet the targets set in Europe. WindEurope estimates that with current build-out rates and expected evolutions until 2030, 351 GW will be installed, falling 100 GW sort of the 425 GW announced target [77]. Wind turbines are placed onshore or offshore, with onshore dominating the wind energy market. Figure 1.1 makes clear that offshore wind additions are increasing both in absolute numbers, but also in their relative share of installed wind power. In 2014 offshore wind was a mere 8% of the total wind power, with its share rising to 15% in 2024. By 2030, it is expected a total of 48 GW of offshore wind (cumulatively) will be installed in Europe, a 65% increase compared to 2024.

The opportunities in the offshore wind energy market have drawn the attention of large utilities companies and project developers, such as Vattenfall. Vattenfall is a Swedish company, which among a large portfolio of electricity generation technologies, develops, owns and operates offshore wind farms, such as the Hollandse Kust Zuid, the largest offshore wind farm in the Netherlands with 1.5 GW of installed power. Lately, Vattenfall has placed a successful bid for a 2GW development in the Netherlands, Ijmuiden Ver Beta, to be build in partnership with renewable investment fund Copenhagen Infrastructure Partners.

1.1.2. Hydrogen

Where electrification is not feasible, alternative fuels such as hydrogen or ammonia are being considered. Hydrogen is the lightest atom of the periodic table and the most abundant element in the universe, with a multitude of use cases. Hydrogen can be used as fuel in fuel cells, helping decarbonize transportation

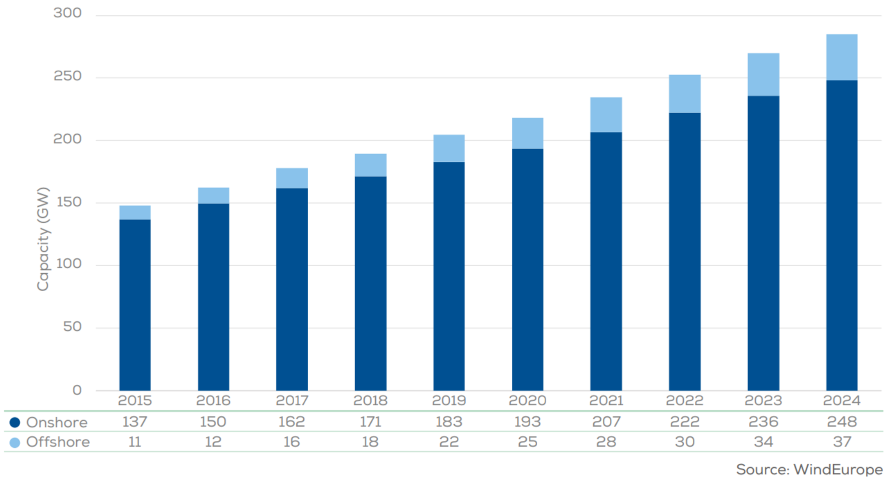

Figure 1.1: Development of onshore and offshore installed capacities in GW in Europe, between 2015 and 2024. *Retrieved from [77].*

sectors which are hard to electrify, such as aviation or shipping. Additionally, hydrogen can be used as feedstock in various industrial process, such as ammonia production for fertilizers or the processing of oil in refineries. As of 2022, 92% of global hydrogen production relies on fossil fuel-based methods, with steam methane reforming (SMR) using natural gas as the dominant process and resulting in 800 million tonnes of CO_2 emissions annually [41]. To reduce the environmental impact and emissions hydrogen can be produced through electrolysis, splitting water into hydrogen. Hydrogen generated through electrolysis and with electricity from renewable sources can be labeled as green hydrogen. The two key technologies utilized for electrolysis in wind farms are Alkaline Electrolysis (AEL) and Proton Exchange Membrane Electrolysis (PEMEC) [33].

A report by the European Joint Research Center estimates that hydrogen demand in Europe will reach 12 Mt in 2030 and 40 Mt in 2050 [19]. In 2024, the installed electrolyzer capacity in Europe amounted to 0.4 GW, constituting only 0.4% of the total hydrogen production capacity [36]. To meet the pledged commitments on green hydrogen deployment, gigawatt-scale electrolyzer capacity additions are required rapidly.

1.2. Investments in offshore wind and hydrogen

Offshore wind and hydrogen investments have to accelerate to meet the targets. Hence, understanding the key factors affecting investments in generation capacity is necessary. The key drivers, affecting investments are identified and discussed in Section 1.2.1. Section 1.2.2 discusses the Key Performance Indicators utilized in evaluating renewable energy investments.

1.2.1. Factors driving investments in offshore wind & hydrogen

The three external factors impacting investments in new offshore parks and hydrogen projects are policy decisions, the interest-rate environment and commodity prices.

Firstly, policy can stimulate investments through subsidy schemes. Until 2022, when Hollandse Kust Zuid made headlines as the first subsidy-free project built, all projects where built through governmental subsidies integrated. Between 2022-2024 projects like Ijmuiden Ver Beta were tendered without any subsidies, reflecting the maturity of offshore wind to achieve profitability. The trend of no-subsidy seems to be reversing in 2025. Several governments, such as Denmark plan a return to subsidy schemes, to increase the participation in auctions which are often under-subscribed [56].

Hydrogen is not as mature as offshore wind and government support schemes are still rolled out.

Currently, governments are shifting the focus to the commercialization of the technology and supporting the project development and procurement of green hydrogen. Around 37 BN € of commitments in hydrogen have been announced by European nations, with almost half of them in Germany [36].

Secondly, renewable energy projects are often financed through debt, at high debt-to-equity (leverage) ratios [25]. Consequently, variations in interest rates affect the cost of borrowing money. From 2022 onwards interest rates increased rapidly reaching 3.75% in 2024, up from -1% in early 2022. This development significantly increases cost-of-capital which can be up to 55% of the total project costs, challenging the feasibility of investing in new projects.

Thirdly, new developments are particularly sensitive to commodity prices. According to a report by McKinsey & Company, between 70% to 80% of an offshore turbine's mass is steel [16]. After 2021, the price of steel and other metals almost tripled, increasing turbine and project costs [38]. Hydrogen is also sensitive to commodity prices

Evidently, these three factors are strongly interlinked. Due to increases in commodity prices and interest rates, the business case for offshore wind projects is less strong, leading to lower capacity additions. States, such as Denmark, can step in with support schemes to stimulate investments and help meet their renewable targets.

1.2.2. Business Case description of offshore wind & hydrogen

Defining the business case of offshore wind and hydrogen goes beyond mere financial returns, including both societal and governance aspects. However, financial returns typically remain the primary driver of investment decisions, as projects are profit-driven.

Key Performance Indicators such as Net Present Value (NPV) and Internal Rate of Return (IRR) or the Levelized Cost of Electricity and Levelized Cost of Hydrogen, are employed to appraise an investment [74]. The former method is based on detailed, annual cashflow analysis, discounted to their present value, while the latter integrates all expected costs and revenues in a single value, presenting the cost per MWh of electricity and cost per kg of hydrogen produced. A detailed definition of the KPIs and Levelized Costs can be found in Section 2.1.4.

IRR is the metric best describing the business case of a farm. It is the discount rate that sets the NPV to zero. Typically, the discount rate is set equal to the firm's Weighted Average Cost of Capital (WACC). The higher the WACC, the more difficult for a project to be economically feasible. WACC is affected by the interest rates and the projects debt-to-equity ratio (gearing). It is the link between the interest-rates (external environment) and their impact on the project's performance

For the project to break even, the Internal Rate of Return has to be at least equal to WACC. This is a necessary but not sufficient condition, since most firms employ a Direct Hurdle Rate (DHR), higher than WACC, to reflect the risk premium of the investment. Meeting and exceeding the DHR is necessary and sufficient condition for a new investment. Recently, RWE announced their DHR has shifted by 0.5 percentage points to 8.5% to reflect increased risks associated with offshore wind [67].

To derive the net cash flows, revenues are also required. For an offshore wind farm, the key revenue sources is sales of electricity either in the spot market or through a long term Power Purchase Agreement (PPA). In case the wind farm integrates hydrogen, revenues can additionally be acquired through the sale of hydrogen via a fixed-price Hydrogen Purchase Agreement (HPA) with an off-taker. Currently, HPAs are the main source of income as a hydrogen market is not developed yet [36]. Due to the absence of a public market, data on the agreed hydrogen prices are scarce.

1.3. Synergies between offshore wind and hydrogen

Synergies between offshore wind and hydrogen, in the form of co-located offshore wind farms with electrolyzers, are an excellent opportunity to solve some of the key issues faced by offshore wind and accelerate the expansion of both technologies. The key benefits of such synergies can be distilled in three areas. Firstly, improvements on the business case of the offshore farms, followed by system-wide positive effects and finally, reduction of the cannibalization effect.

1.3.1. Business case improvements

First and foremost, hydrogen synergies can improve the financial returns of the wind farm, by providing an alternative for low-price hours [29]. In terms of improved business case feasibility, producing hydrogen offshore and transporting it to shore through pipelines can be more economical than power transmission [48]. This can help unlock sites which have strong wind resource, but their exploitation is currently uneconomical.

A TNO white paper on the need for flexibility [44] indicates that, in a low-electrification scenario, coupling hydrogen production with offshore wind could boost the Internal Rate of Return (IRR) by 5–33%. In a high-electrification scenario, IRR improvements could reach 22%, assuming Hydrogen Purchase Agreements remain above 4 €/kg. Installing an electrolyzer stack directly in an offshore wind farm can convert otherwise unprofitable projects with negative NPV into financially viable ones, provided the electrolyzer-to-wind capacity ratio is sufficiently high [29].

1.3.2. System-wide benefits

Supplementarily to profitability, hydrogen integration can help mitigate grid congestion issues, caused by renewables. Grid congestion arises from demand outgrowing the build-out of grid capacity and poses a key issue for the further penetration of renewables. To counter the issue, the Transmission System Operator (TSO) often curtails renewable power from the grid. However, since electrolyzers are dispatchable, they can increase their production when congestion occurs, reducing or prevailing curtailment [34].

With an optimal dispatch program, production of hydrogen can be scheduled for hours with low power prices, characterized by high wind generation, when otherwise wind could be curtailed. A study by [23] showed that if hydrogen is integrated, curtailment of offshore wind can be reduced by up to 24.9%, compared to a scenario with no H2.

Governmental mandates have started on system integration of new offshore capacity, to avoid congestion and subsequently curtailment issues. For example, the recent tender by the Dutch government required system integration through electrolyzers [1]. Vattenfall along with Copenhagen Infrastructure Partners, successfully won the tender process for Ijmuiden Ver Beta, by integrating an electrolyzer of up to 1 GW, installed in the Port of Rotterdam [69].

Additionally, studies point out that the cost of hydrogen produced through Proton Exchange Membrane or Alkaline electrolysis coupled with wind power, is lower compared to the cost of alkaline electrolysis using grid electricity [33]. Therefore, industry and society can gain access to cheaper hydrogen, promoting its adoption.

1.3.3. Cannibalization effect mitigation

Integrating hydrogen can help reduce price cannibalization by offshore wind. Cannibalization refers to the phenomenon where the capture prices of wind and other renewables technologies are reduced, leading to a "self-cannibalization" of market revenues. An indicative effect of price cannibalization are negative day-ahead prices, encountered in times with high renewable production but low demand.

To understand cannibalization, the term value factor is introduced. This metric is defined in equation 1.1 and relates the capture price of a technology to the average market price, indicating the relative value of this technology. Research and market analytics indicate that with increasing share of renewables, value factors for offshore wind will decrease over time, reducing market profitability [10].

$$\text{Value Factor} = \frac{\text{Average Capture Price}}{\text{Average Market Price}} \tag{1.1}$$

Wind's value factor is highly dependent on location, market design and market dynamics. Figure

1.2 indicates increasing offshore wind penetration in Germany can decrease its value factor by up to 20%, if market conditions remain unchanged. Another market, Spain, with higher penetration of solar energy demonstrates stronger value retention, with offshore wind farms losing around 10% of their market value over the course of 30 years [10].

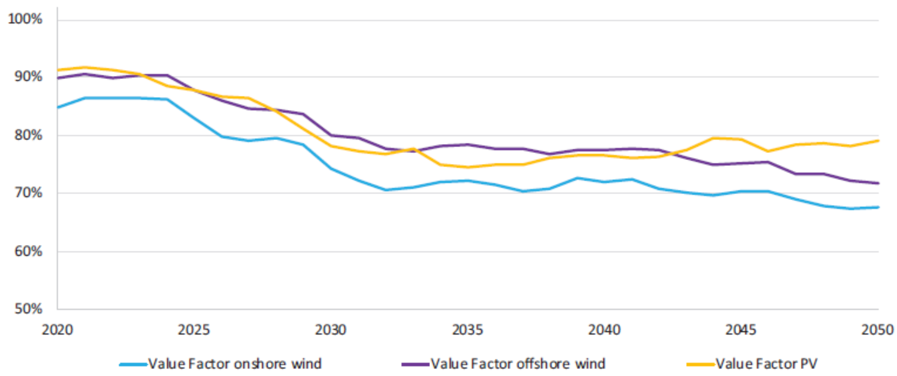

Figure 1.2: Value factor of onshore wind, offshore wind and photovoltaics for Germany, 2020-2050. *Reproduced from [10]*

If no action is taken toward the direction of dispatchability of renewables, price cannibalization effects will continue. Consequently, the business case of offshore wind will get less attractive with more renewable penetration. Fortunately, hydrogen synergies offer the required dispatchability and can mitigate the effects of value-capture loss.

1.3.4. Layouts of hybrid powerplants

To realize the full gain from hydrogen synergies, the electrolyzer and wind farm shall be co-located. Three layouts have been proposed, mostly regarding the location of the electrolyzer with respect to the wind farm [37]. The first layout, **centralized onshore**, utilizes an onshore electrolyzer, while **decentralized offshore** places electrolyzers on each wind turbine. Finally, **centralized offshore** aggregates all hydrogen production in a centralized offshore platform.

For this work, the focus will be on a **centralized onshore** layout. Onshore layouts allow for synergies between hydrogen and offshore wind farms at lower costs. Literature suggests the centralized onshore option has lower lifetime costs and is more competitive in terms of LCOH for both close & shallow waters and deep waters [68]. The cost competitiveness comes from the reduced footprint of the electrolyzer and required Balance of Plant, which are designed for onshore conditions. Additionally, placing the electrolyzers onshore reduces the maintenance needs and could possibly impact the degradation rate of the stack. Generally, placing any infrastructure onshore is less costly, compared to offshore construction.

An onshore layout, as illustrated in Figure 1.3, consists of an offshore wind farm and all necessary infrastructure to transfer the power to shore, namely inter-array-cabling, offshore substation and export cables. To include all components, the offshore substation and export cables are also included in the scope of the project.

Onshore, a transformer station is present, responsible to up the voltage, to allow connection of the wind farm to the grid. Moreover, the electrolyzer stacks and all accompanying infrastructure that enables their operation are part of an onshore centralized layout. The accompanying infrastructure, i.e. desalination plant and power electronic converters are called Balance of Plant.

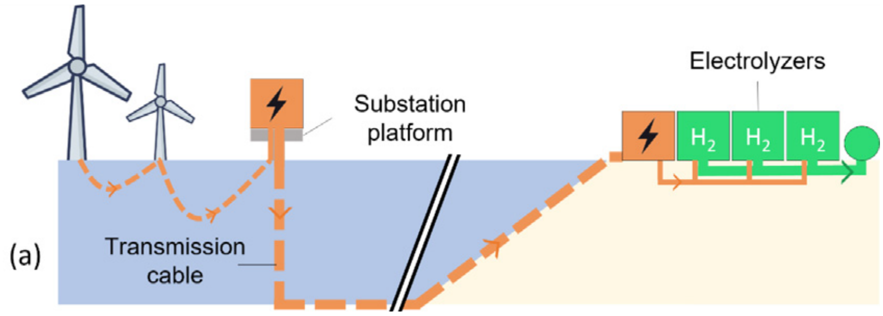

Figure 1.3: Centralized Onshore layout for hydrogen production onshore *Reproduced from [68]*

1.4. Uncertainty

1.4.1. Sources of uncertainty

Offshore Wind

Investments in offshore wind require substantial capital and involve extended timelines. The development phase, typically lasts up to five years. This is followed by a two-year pre-construction period, during which detailed site assessments and rigorous economic appraisals are performed. If the business case remains feasible, a Final Investment Decision is issued and construction starts, spanning an additional two years.

Such projects unfold in an environment of rapid changes in policy, commodity prices and interest rates (Section 1.2.1). These external factors introduce considerable uncertainty. Moreover, the lengthy timelines and the operational challenges inherent to marine settings further amplify unpredictability.

Prior to examining specific sources of uncertainty, it is important to distinguish between "uncertainty" and "risk." In this context, uncertainty refers to parameters whose values are not precisely known at the time decisions must be made—for example, the exact price of turbines at procurement. Risk, relates to events that may arise unexpectedly or with only partially known probabilities, such as a sudden war disrupting supply chains. In other words, uncertainty involves known unknowns in parameter estimation, whereas risk encompasses both known unknowns and unknown unknowns that can have substantial impacts.

Caputo et al. [13] identify nine categories of uncertainty relevant to renewable energy projects: (1) variability in input variables (e.g., wind resource availability); (2) external random events (e.g., natural disasters); (3) uncertainty in internal model parameters (e.g., component failure rates); (4) internal random events (e.g., unexpected equipment failures); (5) financial uncertainties (e.g., fluctuations in the cost of capital); (6) tax uncertainties (e.g., changes in tax regimes); (7) social and political risks (e.g., shifts in permitting or public opposition); (8) market uncertainties (e.g., stochastic variations in power prices); and (9) regulatory uncertainties (e.g., modifications to subsidy schemes).

In preparation to bid for a tender, the project's economic viability is scrutinized intensively. Consequently, all uncertainties that affect costs or revenues must be examined. On the cost side, volatility in major capital expenditures, driven by commodity price fluctuations, requires thorough analysis. On the revenue side, variability in wind resource translates directly into uncertain annual energy production (AEP) and, therefore, revenue forecasts. Revenue uncertainty is further increased by the inherent volatility of power markets.

Offshore Wind & Hydrogen

Offshore wind investments entail a broad range of uncertainties. Integrating an electrolyzer introduces additional sources of uncertainty beyond those inherent to a standalone wind farm. In particular, capital expenditure (CAPEX) and operational expenditure (OPEX) estimates for electrolyzer plants remain imprecise, since industrial-scale deployments are not yet common; consequently, projected costs and expenses span a wide range.

In addition to CAPEX and OPEX uncertainties, the off-take price of hydrogen is uncertain. Because the green hydrogen market is expected to remain niche in the near term, forecasting a reliable hydrogen price is inherently challenging. Additionally, the price of fixed Hydrogen Purchase Agreement cannot be accurately estimated at the time.

1.4.2. Uncertainty Quantification frameworks

Since any hybrid project is capital-intensive, with investment requirements in the order of several billion euros, quantifying uncertainty is necessary for correct identification of the project's outcomes and risk profile. The main framework to quantify uncertainties is to first identify a possible sources of uncertainty and a range for the uncertain inputs, and whether the parameters follow a statistical distribution. Secondly, the uncertainties have to be sampled and propagated through the model, simulating the technical and economical aspects of the renewable project. The most common methodology utilized is Monte Carlo, which randomly samples the distribution of the input variables [51]. Finally, the impact of the uncertainties on the business case has to be evaluated, though statistical averaging of the Net Present Value, Internal Rate of Return and Levelized Cost of Electricity [43], [45], [13].

1.5. Research scope

While the benefits of combining hydrogen and offshore wind are well established, one crucial question remains unanswered: the overall impact on business case uncertainty. Although previous studies have examined offshore wind economics under uncertainty and a few have explored wind and hydrogen hybrid configurations in isolation, none have systematically compared the uncertainty distributions of a full-scale offshore wind farm both with and without an onshore electrolyzer under identical stochastic inputs. This work is the first to build a 2 GW North Sea-representative offshore-wind model, add a 400 MW PEM electrolyzer in an onshore-centralized layout, and then run Monte Carlo simulations to directly quantify how hydrogen affects both the median P_{50} and extreme outcomes (P_{10}, P_{90}) for NPV and IRR. Additionally, by applying rank correlations across both baseline and hybrid cases, the study uniquely identifies which uncertainty drivers, from commodity prices, vessel day rates, CAPEX and power market volatility shift in relative importance when hydrogen is coupled.

Additionally, collaborating with Vattenfall on this research topic, essential barriers can be lifted regarding the accuracy of the inputs. Access to informed price quotes and exact project layouts is very challenging, due to strict confidentiality. As one of the largest developers in Europe, Vattenfall poses a depth and width of experience in developing offshore wind, that can be leveraged to accurately model the uncertainties.

On the one hand, integrating a second energy carrier can increase revenues, compared to a base-case where only power is exported, by curbing curtailment and increasing the value factor of an offshore wind farm. Through the additional flexibility of an additional energy-carrier, the dependence on the electricity price can be mitigated and the uncertainties on the expected revenue can be mitigated. On the other hand, introducing a new technology with uncertain installation and lifetime costs, adds complexity that could erode these expected gains from hydrogen integration. These open questions lead to the main research question, which is formulated below.

Main Research Question

How are uncertainties in the business case of an offshore wind project affected by the addition of hydrogen plant?

In order to achieve this research objective, five steps must be taken. Each of these steps comprises a sub objective directly related to the overall research objective. These are :

1. How to model the business case of an offshore wind farm?
2. What are the main uncertainties in the business case of an offshore wind project?
3. How to model the business case of an offshore wind farm with hydrogen integration?
4. What are the main uncertainties in the business case of an offshore wind project with H2 synergy?

With the results of this thesis Vattenfall can improve the decision-making capability regarding investment decision in hybrid powerplants. Hybrid powerplants are novel themselves, let alone their uncertainty quantification. Nevertheless, understanding the impact of hydrogen inclusion on uncertainty, translates to an improved understanding of project uncertainties. As an extension and based on the risk appetite a project can be put forward, depending not only on the absolute financial returns, but also on a quantified risk.

Demonstrating the risk profile of a hybrid project, compared to a standalone wind farm can help promote the further adoption of hydrogen. If hydrogen is a means to simultaneously improve the financial returns of the wind farm and reduce uncertainties, more investments can be made. Hence, society can benefit from the decarbonization benefits of more renewable electricity and green hydrogen, at competitive prices.

1.6. Approach

To answer the main research question, the following approach is proposed:

Firstly, a representative layout of a 2 GW offshore wind farm is set up including an offshore substation and HVAC transmission to shore. The wind farm includes extensive modeling of the capital expenditure and maintenance costs based on proprietary data, producing results on the lifetime costs and revenues of the project.

The offshore farm modelled in the baseline case assumes the offshore wind farm sells all of its output into the day-ahead market, fully exposing it to market volatility. Maintaining full merchant exposure in the baseline is a methodological choice made to ensure a like-for-like comparison with the hydrogen-integrated scenario. Hedging the baseline case against day-ahead prices would make it impossible to isolate the effect of H2 integration on revenue de-risking. Fundamentally, an electrolyzer is installed to arbitrage the low price hours, but if a price swap scheme is in place, no arbitrage options are present.

Full merchant exposure is also enabled by on-balance-sheet financing, the typical financing structure employed by Vattenfall. Lenders do not directly require securities or the collateral guarantees, allowing the developer to take higher risks, through full market exposure. Based on this baseline case and the full merchant-exposure scheme, uncertainties in major CAPEX components, arising from uncertainties in commodities prices are modelled. The uncertainties included in the fields of component CAPEX, vessel uncertainties and revenue uncertainties are thoroughly analyzed in Sections 3.2.3 to 3.2.6. Defining the uncertainties is based on literature and expert interviews, while quantifying their impact is done through 1000 Monte Carlo simulations.

To model the synergy of an offshore wind farm with an onshore electrolyzer, the layout of the powerplant is expanded to include a 400 MW Proton Exchange Membrane electrolyzer on the shore. For this hybrid case, the same uncertainties as the baseline case are simulated and they are extended to include CAPEX and OPEX uncertainties of the electrolyzer plant. Again, 1000 Monte Carlo simulations are applied to quantify their impact.

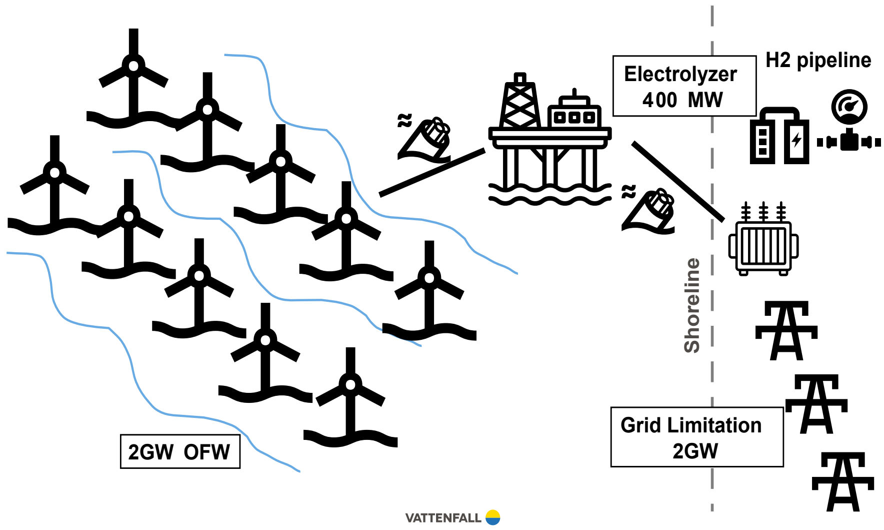

Figure 1.4: Baseline offshore wind farm and hydrogen integration schematic

Through the proposed methodology, the impact of adding an onshore electrolyzer on the project's NPV and IRR uncertainty can be modeled. Modelling both a baseline and hybrid case allows for direct comparison in terms of net profitability and uncertainty and can help take optimal decisions.

1.7. Modelling assumptions

Several assumptions and scope boundaries underlie this analysis:

1. Data: Data related to investment costs are based on standard industry forecasts, corresponding to the expected Commercial Operation Date of the project. The data have been provided by Vattenfall and represent a generic, but realistic project. None of the data utilized come from supplier quotes.
2. Techno-economic model: Vattenfall's proprietary model serves as a black box, with its internal cost algorithms not modified.
3. Hybrid layout: The study adopts an onshore centralized electrolyzer layout due to its lower O&M complexity and cost advantage over offshore decentralized hydrogen production.
4. Timeline: The investigated project is placed just before a decision to bid for tender, reflecting the required detail to drive this decision.
5. Revenue Exposure: The wind farm retains full merchant exposure to electricity prices. Hydrogen revenue is based on a fixed off-take price through a Hydrogen Purchase Agreement (HPA) at 4 €/kg.
6. Hydrogen off-take: An infinite pipeline capacity is assumed, such that all hydrogen produced can be sold at the contracted price. Upstream regulatory hurdles, grid injection tariffs, and end-user demand fluctuations are outside the model's scope.
7. Project lifetime: Both wind and electrolyzer assets operate for 35 years. Decommissioning costs after year 35 are excluded from the uncertainty analysis.
8. Exogenous factors: Broader electrolyzer market developments, such as breakthrough technologies, are not explicitly modeled but are captured indirectly through the uncertainty ranges.

2
Literature Survey

2.1. Techno-economic analysis of hybrid projects

This chapter introduces the techno-economic evaluation of integrated wind-hydrogen systems. It begins by examining the key cost components, providing a detailed breakdown of offshore wind and electrolyzer expenses. Subsequently, the revenue streams associated with hybrid assets are presented. Finally, two methodologies for appraising hybrid assets are introduced, emphasizing project financing considerations and the associated cost of capital.

2.1.1. Offshore Wind Farm components and their costs

The costs of a hybrid asset can be broken down in three distinct categories, based on the lifetime phase of the project. First, Capital Expenditure (CAPEX) refers to the procurement and installation costs. Secondly, the Operation & Maintenance Expenditure (OPEX) refers to all the expenses incurred for the operation and maintenance of the asset during its useful lifetime. Finally, the Decommissioning Expenditure (DEPEX) includes all the costs related to the decommissioning of the wind farm and electrolyzers once they reach their useful life. Analyzing costs at the component level is necessary, as the in-house cost model of Vattenfall includes costs at minimum in the component level.

According to data compiled by [72] the CAPEX breakdown of an offshore wind development project can be seen in Table 2.1. Based on this ranking, the individual cost components will be analyzed further below:

Item	Percentage of CAPEX
Wind turbines	30-50%
Substation and electrical infrastructure	15-30%
Foundations	15-25%
Component installation	0-30%
Other	8%

Table 2.1: CAPEX breakdown per component for an offshore wind farm based on 2013 data. Reproduced from [72]

Wind Turbines

The main cost component of any project is the procurement of the wind turbines, which accounts anywhere from 33% to 50% of the total CAPEX, according to estimates from different sources [46], [24].

The price of the wind turbine package, including rotor, nacelle and tower, varies based on a number of parameters. The commissioning year, wind turbine technology, and any agreements between developers and turbine manufactures affect the final pricing. CAPEX quotes reported are mostly assumptions, due to the commercially sensitive nature of the quotes, often under Non Disclosure Agreements.

An accurate estimate for purchasing an offshore turbine in 2025 is around 1.1M €/MW according to data published by manufacturer Vestas [40]. Between 2020 and 2022 a 37% increase in turbine price has been observed, as expressed in the price per MW installed from Figure 2.1. Prices in MW installed includes procuring the wind turbine and its auxiliaries and installation. Latest opinions from experts indicate that current prices per MW installed, are in the range of 1.5 - 1.9 M €/MW, indicating a further cost increase from 2022. As the component breakdown of Figure 2.1 indicates, costs for rotor blades have been constantly decreasing, while gearbox and generator costs have been increasing. The former development can be attributed to the improved manufacturing capabilities with composites, while the latter to the surging metal prices as discussed in Section 1.2.1.

The trend of rapid cost increases is expected to ease out, with the overall CAPEX per MW installed projected to decline after 2024, as illustrated in Figure 2.2. This Figure presents the trends in CAPEX per kW installed in Europe, Asia, and globally, showcasing a consistent drop in costs, which stabilizes after 2023. However, projects in Europe can expect a reduction in CAPEX starting from 2026. This anticipated decrease can be attributed to an expected reduction in turbine prices and declining inflationary pressures, according to expert opinion. Additionally, the withdrawal of government subsidies could reduce the demand for new wind turbines and help rationalize the market. Research from China indicates that the phasing-out of subsidies could lead to a decrease in prices and correct any market distortions created by the subsidization of unprofitable projects [53].

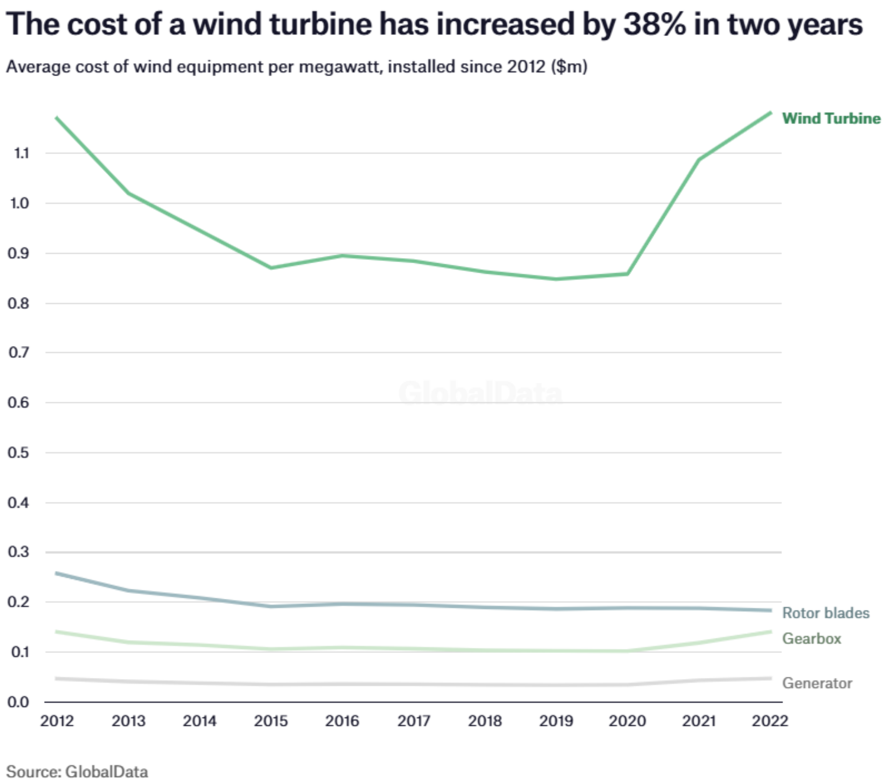

Figure 2.1: Wind Turbine price per MW of installed capacity, with breakdown of components. *Reproduced from [57]*

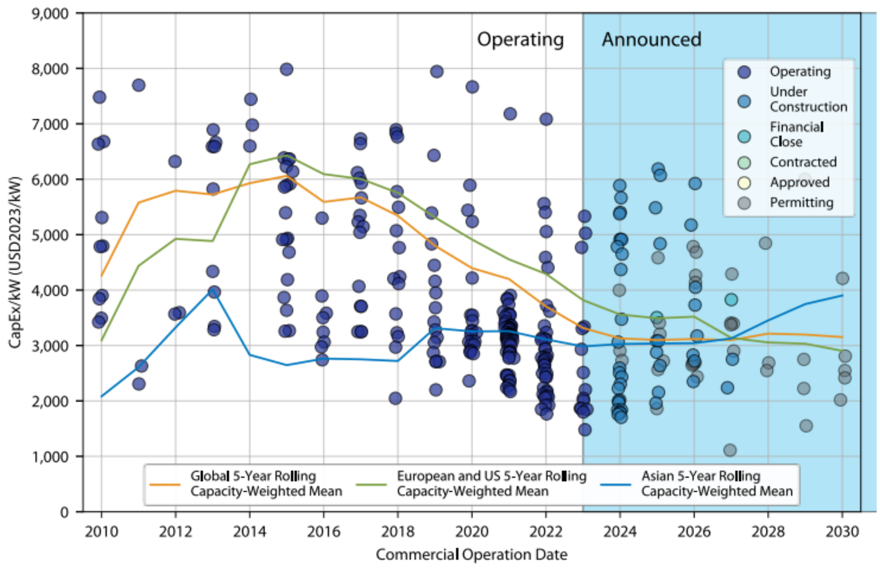

Figure 2.2: Trends on offshore-wind CAPEX, 5-year rolling average for Global, European and Asian projects, operating and announced. *Reproduced from [55]*

Foundations

Another major cost component is the manufacturing and installation of the foundations. Monopiles will be the focus of this section, as these are the most common type utilized in bottom-fixed wind farms. Monopiles are essentially steel tubes of large diameters, in the order of 10 meters for XL monopiles deployed to support multi-MW turbines. Therefore, steel price and manufacturing costs are the main drivers for the foundation costs [64]. Additionally, the water depth dictates the necessary length of the monopile, which in turns affects the mass, adding another cost driver.

Except manufacturing the monopiles, significant costs are incurred during the installation procedure. The installation involves vessels that hammer the piles in the seabed and a plethora of other vessels to install additional components on the foundation, such as scour protection. An approximation of the costs related to foundations found in literature is 576 k €/MW of installed capacity [46] [1]. According to [50] for projects installed between 2014 and 2017 around 5.93 vessel-days were required per turbine and foundation. or 1.06 vessel-days per MW. With the average rates estimated from table 2.2[2] installing a 14 MW turbine, using a turbine installation vessel would require € 4.2 M, without accounting for any delays or other vessel requirements.

Vessel type	Daily rate (€)
Turbine installation vessel	171,000 – 285,000
Jack-up barge	114,000 – 205,200
Crane barge	91,200 – 101,400
Cargo barge	34,200–57,000
Tug boat	1,140 – 5,700

Table 2.2: Indicative rates for vessel. *Reproduced from [50]*

Vessel rates should be interpreted cautiously, as hire rates and fuel costs are subject to frequent fluctuations. According to expert insights from TU Delft, the current hiring rates for vessels can be

[1]Currency originally in £, converted to € with the 31.12.2020 conversion rate of 1€= 0.9£
[2]Currency originally in $, converted to € with the 31.12.2018 conversion rate of 1€= 1.14$

double or up to three times what is listed in Table 2.2. This rapid increase in costs compared to 2018, the reference year of the table, is attributable to the high demand and limited supply of vessels for offshore wind. Additionally, the uprating of turbines requires a constant adaption of vessels, further creating bottlenecks in the supply chain [15]. To ease the pressures on supply chain, vessel owners, have increased their orders for new builds [11]. Overall, the rapid increase in prices indicates high uncertainty in installation costs, as such dynamic price fluctuations introduce variability into the installation CAPEX.

Inter array and export cables

Inter array cabling refers to the electrical cables which connect the wind turbines in strings and then transfers the power to the off- or onshore substations. Inter-array cables have standardized voltage rating of 33 kV, 66 kV or 132 kV. With increases in farm rated output, the voltage rating of the cables tends to increase to reduce losses and manage the higher power requirements. Inter-array cabling has two CAPEX components, manufacturing and installation, amounting to around 241k €/MW [3] of installed capacity, and 4.6% of the total CAPEX according to the 2024 NREL survey [75]. As with most components, cable cost is heavily influenced by commodity prices of aluminum or copper, which are highly volatile. To minimize costs, cabling layout and grouping of wind turbines is subject to algorithmic optimization [27].

Regarding the export cable, HVDC will be the standard for transmitting power to shore in the future, based on the proposal by TenneT, who is responsible for the connections of the grid in Germany and the Netherlands. TenneT promotes a 2 GW connection scheme across the entire North Sea, with the aim of standardizing the export cable and offshore substation designs [7]. In general, HVDC is already the standard way to transfer power to shore, for distances greater than 100 km, as this is more economical due to reduced power losses compared to HVAC [28]. According to research on the optimal way to connect the DogerBank 2.4 GW wind farm in the UK to the central grid, the CAPEX for an HVDC cable is 1.1 M £/km [59].

2.1.2. Electrolyzer key components and their costs

The electrolyzer is an integral part of the integrated wind/hydrogen system, converting electricity to hydrogen. Proton Exchange Membrane Electrolyzers (PEMEC) are the most probable candidates for integration with renewables, due to their high flexibility and low cold start-times. Costs are expected to drop as a consequence of economies of scales, learning rates, and technological improvements, with [66] estimating a learning rate of 25-30%. The same researchers estimate CAPEX around 320-377 $/MW [4]for a PEMEC with entry-into-service in 2030 and plant capacities over 100 MW. The expected evolution of the CAPEX from 2015 to 2030 based on the plant capacity can be observed in Figure 2.3. The CAPEX number refers to investments in stacks, Balance of Plant and all accompanying equipment.

Additional research, by [32], dives deeper into the expected cost evolution of PEMEC by developing a model for the stack voltage and current density. The authors compare a state-of-the-art PEMEC with a current density of $2A\backslash cm^2$ with a next-generation PEMEC with expected current density around $4A\backslash cm^2$. Additionally, the authors consider uncertainties in stack, civil engineering and construction costs to determine ranges of CAPEX for different plant capacities. Figure 2.4 indicates the cost range with the aforementioned uncertainties, showing a general trend of decreasing costs with increasing plant capacity. This effect stems from the overhead expenses for the Balance of Plant, referring to all the supporting technologies to enable the operation of the electrolyzer, which is spread out across a larger installed capacity. Additionally, the potential to decrease CAPEX requirements of the NextGen PEMEC is between 25 to 50% between 2-100 MW. The cost reduction between the two generations is attributed to lower stack costs [32]. For a plant in the range of 100 MW the expected CAPEX is around

[3] Currency originally in $, converted to € with the 31.12.2024 conversion rate of 1€= 1.04$
[4] Currency originally in $, converted to € with the 31.12.2022 conversion rate of 1€= 1.06$

600 k € /MW, with a range between 580 and 700 k € /MW. These costs include stacks, BoP and all accompanying equipment.

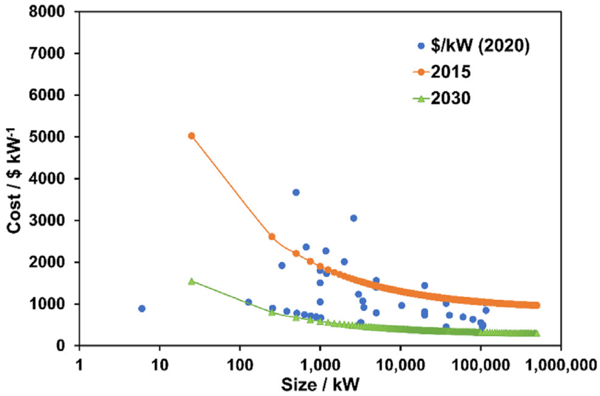

Figure 2.3: PEMEC cost from literature review and best-fit equation for 2015 and 2030. *Reproduced from [66]*

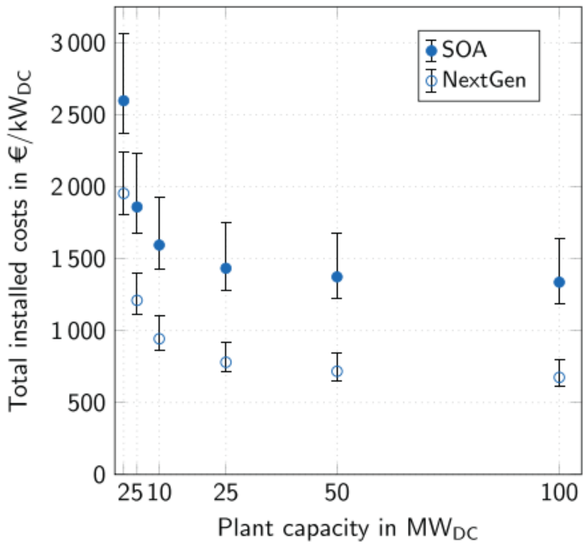

Figure 2.4: CAPEX per kW of installed PEMEC based on plant size. SOA: State-of-the-art 2023 NextGeN: Next generation of PEMEC. *Reproduced from [32].*

Another team of researchers calculated the expected cost decreases of AEL and PEMEC stacks until 2030 through bottom-up and top-down approaches [49]. On the one hand, the bottom-up approach works by breaking down the PEMEC cost to the fundamental components and estimating the cost for each component based on a first-principles approach. On the other hand, the top-down approach tries to extrapolate the costs by utilizing aggregate costs, such as price quotes from manufacturers. A key technological parameter driving the costs is the current density, which increases from $2A\backslash cm^2$ in 2020 to $3.5A\backslash cm^2$ in 2030 [49], a lower value compared to [32]. Current density is an important cost driver, as the higher the current density handled by the electrolyzer, the lower the material requirements. Overall, [49] estimate a PEMEC installation cost of 63-243 k € /MW in 2030, with increased current density and reduced use of expensive materials for membranes as the key drivers. Since this quote only includes stack costs, the authors have adjusted their estimates to include BoP and all accompanying equipment, with total CAPEX between 359-1300 k € /MW.

In a direct comparison between PEMEC and AEL, [33] estimate the CAPEX for the former at 2000 k € /MW and the latter at 1000 k € /MW. As the authors used a time-weighted average for their estimates of costs, they highlight that AEL cost is less volatile in time, since the technology is more mature with less significant learning effects are expected. Finally, the CAPEX of PEMEC and AEL compared to the total cost of a 504 MW offshore wind farm with a 504 WM electrolyzer, are 9.4% and 19.2% respectively. Additionally, the OPEX of an Alkaline electrolyzer is expected to constitute 7.2% of the hybrid asset's total OPEX at 6069 k €/annum. PEMEC OPEX is significantly higher at 19.2% of total OPEX at 10892 k €/annum.

[32] highlight the importance of OPEX in the total lifetime costs of a PEMEC and especially the electricity price as the main OPEX component, an argument further supported by [49]. Krihnan et.al estimate that for a steady electricity purchase price of 50 €/MWh, 8000 operational hours a year, a depreciation time (stack lifetime) of 10 years and an IRR of 8%, the OPEX dominates the LCOH by around 67-83%. A report by KPMG estimates that the fixed OPEX associated with operation & maintenance of the stacks is around 2-4% depending on whether a stack replacement is included [2]. Regarding stack lifetime, the consideration of this as an uncertainty by [49] aligns well with prevailing opinions of industry, especially for stacks placed near-shore or offshore.

Electrolyzers are depletable due to the gradual degradation of the stack membranes, with an average lifetime of 40000 hours according to [80]. The authors estimate that for mid to large scale applications, a stack life of around 10 years can be expected, with the potential to increase to 20 years in the near future. A report by Deloitte is more optimistic on the lifetime of PEM, estimating the value to be around 75000 hours for an electrolyzer operational in 2030 [21]. Therefore, the electrolyzer will need to replaced at least once in the 35 years of project lifetime, with significant cost. The replacement costs for an electrolyzer are estimated at 10-15% of the initial CAPEX, based on a report by the Department of Energy [63] and as high as 30-40% of the initial CAPEX by [21].

All in all, a wide range of CAPEX values are found in literature for a Proton Exchange Membrane Electrolyzer in 2030, ranging from as low as 63 k €/MW to as high as 2000 k €/MW, as can be seen in the summarizing Table 2.3. This range is broad, spanning an order of magnitude difference between the lowest and highest estimates, deeming the electrolyzer CAPEX one key variable for the uncertainty analysis. Similar uncertainties are expected in the lifetime of the electrolyzer and the replacement CAPEX, indicating the large uncertainties stemming from the lack of operational experience with PEM electrolysis on a multi-MW scale.

Source	CAPEX in k €/MW, including auxiliaries	Entry into Service
[66]	320-400	2030
[32]	580-720	2030
[49]	359-1300	2030
[33]	2000	2019

Table 2.3: Summarizing table from literature regarding electrolyzer CAPEX including necessary auxiliaries such as Balance of Plant and desalination units.

2.1.3. Sizing of a hybrid powerplant

With the unit costs of an offshore farm and the electrolysis equipment known, the next step is to optimally size a hybrid powerplant to maximize its profitability. Along with an optimal dispatch schedule, an optimal split between the installed wind and electrolyzer capacity is necessary. Literature indicates that increasing the hydrogen production against electricity from 20% to 100%, leads to increased Net Present Value (NPV), Internal Rate of Return (IRR) and decrease Levelized Cost of Electricity (LCOE), as evident from Figure 2.5.

Increasing hydrogen output can turn an unprofitable project to a profitable one, specially in the case when the High Voltage Direct Current transmission is replaced by a hydrogen pipeline in case B3, on the right of Figure 2.5. This finding underscores the importance of considering hydrogen synergies in wind farms further offshore, deploying HVDC connections. Often, a hydrogen pipeline is more economic compared to a long-distance export cable.

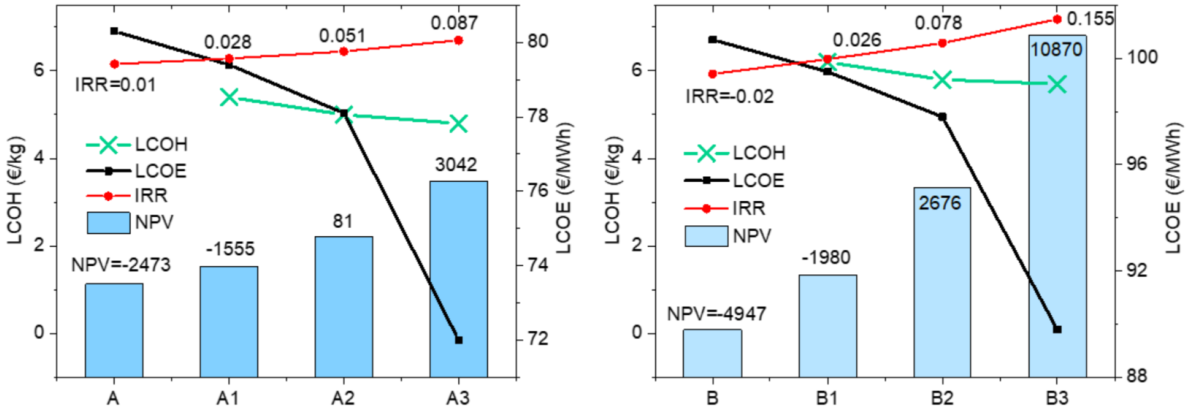

Figure 2.5: Left : Offshore Wind Farm with HVAC and hydrogen share increasing from 0% to 100%. Right: Offshore Wind Farm with HVDC and hydrogen share increasing from 0% to 100%, at 20% increments. *Reproduced from [29]*

2.1.4. Economic analysis models

To evaluate the competitiveness of an investment in electricity or hydrogen, two different methods exist. Firstly, the financial analysis appraises the project based on the Internal Rate of Return, Net Present Value and other financial Key Performance Indicators (KPIs). Secondly, the Levelized Cost of Energy [74] can be utilized. The financial model methodology is based on detailed modeling of the expected cash flows of the project. On the other hand, the Levelized Cost of Energy approach is based on calculating the cost per MWh of electricity or per kg hydrogen produced.

Financial Analysis

The financial analysis is based on the calculation of several KPIs, with the two most prominent being the Net Present Value (NPV) and Internal Rate of Return (IRR). NPV is defined as the sum of the future cashflows, discounted to the present adjusting for the time-value of money, as seen in equation 2.1. A positive NPV indicates the project is profitable, and among two investments, the one with the larger NPV is preferred. The cashflows are discounted to the present based on a discount factor. For the discount factor i the Weighted Cost of Capital (WACC) is often used, reflecting the cost of money to the company.

NPV is widely implemented in evaluating investments, but has two limitations. Firstly, NPV is insensitive to project size and does in general favor larger projects. A large project could include large sums of money but small margins, leading to a large NPV. This drawback means that NPV does not consider the returns relative to the invested capital. Secondly, NPV calculation relies heavily on long-term predictions of future costs and revenues, with a high degree of uncertainty. For example a key uncertainty in long-term revenues is the price of electricity or hydrogen.

$$NPV = \sum_{t=0}^{T} \frac{R_t}{(1+i)^t} \tag{2.1}$$

where:

R_t	Net cash flow at time-period t
i	discount factor
t	time period t

The Internal Rate of Return addresses the insensitivity of NPV to project returns. IRR is defined as the discount factor setting the NPV to zero and can be calculated through iterative solution of equation

2.2. IRR can be interpreted as the expected annual growth of the investment. If IRR is larger than the hurdle rate, a minimum return on investment that the shareholders set, then the investment is deemed profitable. Again, the hurdle rate is usually defined by the WACC, adjusted for the markup profit that the business decides. In short, IRR has to at least be above WACC to signal an investment profitable. A pitfall of IRR is that it could favor projects with shorter timespans, as they will tend to have higher IRR. Considering the pitfalls of both NPV and IRR, it is necessary to examine both KPIs when evaluating an investment, as they work in complimentary manners.

$$\sum_{t=0}^{T} \frac{R_t}{(1+IRR)^t} = 0 \tag{2.2}$$

Levelized cost Electricity, Levelized Cost of Hydrogen

In the context of hybrid wind/hydrogen assets, two definitions of the Levelized Cost of Energy are relevant, the Levelized Cost of Electricity (LCOE) and Levelized Cost of Hydrogen (LCOH). The most widely used metric for LCOE in Europe is the one by the Department of Business, Energy & Industrial Strategy (BEIS) of the UK (equation 2.4).

Similarly, the Levelized Cost of Hydrogen is defined in equation 2.3, based on the definition of [17]. This definition of LCOH discounts both costs and hydrogen production. LCOH includes the variable operating costs V_t due to the supply of water and electricity. These costs are negligible for an offshore farm.

$$LCOH = \frac{\sum_{t=1}^{T} \frac{C_t+O_t+V_t}{(1+d)^t}}{\sum_{t=1}^{T} \frac{H_t}{(1+d)^t}} \tag{2.3}$$

where :

C_t	Capital cost in period t, including stacks, balance of plant, other
O_t	Operating Cost in period t, including maintenance,
V_t	Variable Operating Cost in period t, including electricity and water costs
E_t	Hydrogen production in period t
d	discount rate

By definition, LCOE and LCOH do not include revenues, therefore there is not a direct way to infer the business case viability from these metrics compared to NPV and IRR. LCOE and LCOH indirectly refer to the price to which the electricity should be sold at minimum to cover CAPEX and OPEX along with the cost of capital, granted WACC has been used as the discount rate.

$$LCOE_{BEIS} = \frac{NPV_{costs}}{NPE} = \frac{\sum_{t=1}^{T} \frac{C_t+O_t+V_t}{(1+d)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+d)^t}} \tag{2.4}$$

where :

C_t	Capital cost in period t, including decommissioning
O_t	Fixed Operating Cost in period t
V_t	Variable Operating Cost in period t
E_t	Energy generation in period t
d	discount rate

LCOE and LCOH are often reported by large institutions and policy bodies who track the costs of renewable energy. For offshore wind, LCOE has been dropping since 2001, but with notable fluctuations, as seen in Figure 2.6. From the 2011 peak, global LCOE has fallen more than 60% in 2023 with values around 57-67€\MWh. In Europe, the average LCOE in 2023 was 61 €/ MWh, with the cheapest average LCOE in Denmark with 43 €/MWh and the most expensive in Belgium with 81 €/ MWh [3] [5].

[5]Values originally in $ and have been converted to € with the 31.12.2023 conversion rate of 1€= 1.10$

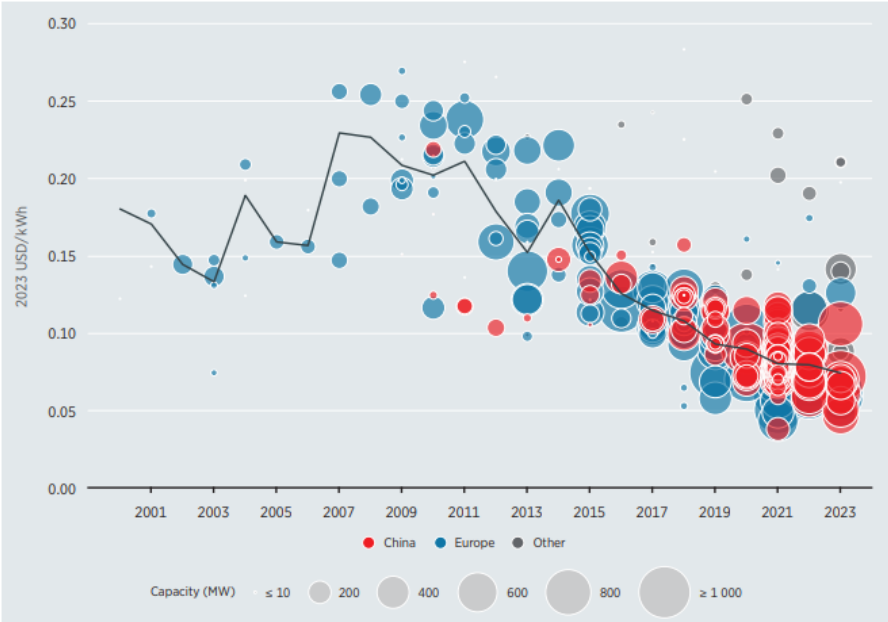

Figure 2.6: Project costs and in 2023 $ / kWh and global weighted averaged of newly installed capacity. *Reproduced from [3]*

Frauenhofer Institute estimates an LCoE for offshore wind in Germany 53-98 € /MWh [39].

Regarding LCOH, investment bank Lazard publishes some LCOH estimates based on the electrolyzer rated capacity, electricity price and electrolyzer CAPEX. For CAPEX values between 672-814 €/MW and electricity prices between 18-38€, for a PEM electrolyzer of 100 MW, the LCOH values vary between 1.3 €/ kg to 2.2 €/kg [52] [6]. Another report by consulting firm Agora-Energiewende on the LCOH indicates that for an MW scale electrolyzer in Europe, LCOH is around 7 € /kg. [4]. Other research focused on the Iberian Peninsula identifies, based on various sources, that for a PEMEC coupled with an offshore wind farm, the LCOH ranges between 2.4-4.2 € /kg [12]. Studies focused on offshore wind and hydrogen hubs in the North Sea estimate the LCOH at 1.4 € /kg.

2.1.5. On-balance sheet financing

When financing large infrastructure projects such as renewable energy developments, two approaches are generally considered, on-balance sheet financing and project financing. Since Vattenfall mostly deploys on-balance sheet financing, the focus will be addressed there.

With on-balance sheet financing the organization performing the investment provides equity and debt to the project directly, and includes the loan obligations on its balance sheet. The organization can acquire funds by borrowing money in the form of bonds, finance the project with 100% equity, or a combination of both. On-balance sheet financing is most common when the project in question is part of the core business, such as vertically integrated utilities investing in an offshore wind farm.

On-balance sheet financing is beneficial when the company can leverage its credit score to secure lending through low-interest bonds. For example, Vattenfall has issued bonds worth 1 BN € with yields between 0.125-0.5%. Taking advantage of its status as a large utility with steady cashflows and good governance, it can secure financing with lower interest rates compared to a bank loan. One main disadvantage of on-balance sheet financing is that the main organization has 100% exposure to the project's risks. A current example is the Danish developer Orsted, which had balance-sheet-financed Ocean Wind 1 and 2 in the US. After deciding to cease the development, Orsted had to incur impairments on the balance-sheet of up to 16 BN DKK (2 BN €), due to the elected financing strategy [60].

[6] Values originally in $ and have been converted to € with the 31.12.2021 conversion rate of 1€= 1.13

2.1.6. Cost of Capital

The financing methodology and the capital structure in terms of equity-debt ratio are two key decisions a developer will take before reaching Final Investment Decision. The financing structure affects the investment decision in two distinct ways. First, if money is borrowed it has to be repaid with interest over the agreed loan term, reducing the available cash flows. Secondly, the associated cost of capital which stems directly from the financing structure is often used as the hurdle rate. Therefore, the higher the cost of capital, the higher the IRR that a new project has to yield to be profitable. The cost of capital is quantified through the Weighted Average Cost of Capital (WACC), defined in equation 2.5. WACC incorporates both costs of debt and equity, corresponding to the first and second term of the equation respectively.

$$WACC = \frac{D}{D+E} \cdot R_d + \frac{E}{D+E} \cdot R_e \tag{2.5}$$

where:

D	the total debt
E	the total equity
R_d	the cost of debt
R_e	the cost equity

The cost of debt R_d can be straightforwardly calculated from equation 2.6 with the debt interest rate usually known. Note that the effective interest rate is reduced by the corporate tax rate, as in most jurisdictions debt payments are considered expenses, therefore reducing taxable income.

$$R_d = \text{debt interest rate} \cdot (1 - \text{corporate tax rate}) \tag{2.6}$$

Deriving the cost of equity R_e is more complicated and requires financial modeling. Two main methodologies are available, Capital Asset Pricing Model (CAPM) and Dividend Capitalization Model (DCM). The former has a broader application to various types of assets, while the latter is applied to appraise investments and companies paying out dividends. For cases of corporate or project financing of renewable energy, CAPM is the most relevant one. The fundamental equation to derive the R_e is found in equation 2.7. Fundamentally, the CAPM model calculates the cost of equity by adjusting the risk-free rate by the asset's market risk premium $(R_m - R_f)$ multiplied with β.

$$R_e = R_f + \beta \cdot (R_m - R_f) \tag{2.7}$$

where:

R_e	the cost of equity
β	the securities beta, indicating the volatility of the stock compared to the general market
R_m	the expected market returns
R_f	the risk-free return

To analyze the terms individually, R_f serves as the base rate of what returns can they expect risk-free. β is defined in equation 2.8, and is a metric for the stocks volatility compared to the market volatility. A β value higher than 1 signifies more volatility than the general market, therefore a high risk and returns are expected. A β value lower than 1 is associated with a stock less volatile than the general market, with expected returns and expected risk decreasing. Finally, R_m is the expected market returns for the period. A common methodology to estimate R_m is to consider the annualized returns of major stock indexes over long periods.

$$\beta = \frac{Covariance(Asset, Market)}{Variance(Market)} \tag{2.8}$$

Estimating WACC is a critical part of developing renewables, as evidently the lower the WACC the more compelling the investments become. Data on WACC of already developed projects are hard to come across due to the confidential nature of the metric and published data are under scrutiny, due to heavy use of assumptions [73]. Additionally, WACC varies over time due to the variation of the underlying cost of debt and cost of equity, impacting both loan payments, market risk premium and return on equity.

Another aspect influencing the cost of capital is risk perception by lenders. Risk perception is dynamic, with offshore wind now considered less risky compared to 10 years ago due to the accumulated experience of developers and banks. Between 2011-2019 the spread between the LIBOR, an interest rate reference in GBP, and the loans for offshore developers had steadily dropped from 350 to 150 bps (1 bps = 0.01%), according to a PwC study [65].

Frauenhofer Institute currently estimates WACC for offshore wind developments in Europe at 7.9% [39] while another Pan-European study by [22] indicated that between 2017 and 2020 WACC of offshore wind had an average value of 3.7%. Evidently, there has been a significant increase in the cost of capital for new developments mostly driven by the increasing interest rates.

The financing structure affects the cash flows and the evaluation of uncertainty in a project. In case of project financing, a more conservative approach is taken from the lenders in scrutinizing the business case. Lenders have a limited upside, capped by the interest rate and a large downside. Therefore, they evaluate the business cases conservatively, using KPIs describing the outcome of the investment 90% of the times (P90-values). On the contrary, if a project is financed on-balance-sheet, the project owner can accept more optimistic estimates of the investment KPIs such as 50%, since it holds both the upside and downside of the investment and is less risk-averse.

2.2. Uncertainty Quantification in hybrid projects

As evident from Section 2.1 there is considerable variability in cost estimates in literature, stemming not from lack of information, but from the inherent uncertainty and volatility of offshore wind and hydrogen markets. This literature gap highlights the pressing need for uncertainty quantification methodologies, which are essential for accurately assessing the financial KPIs discussed.

First, the main uncertainties considered in evaluating the economic potential of coupled hydrogen-wind systems will be described, along with some additional aspects that often are omitted in literature but are essential to developers. After understanding the main sources of uncertainty, a systematic review of the statistical methodologies employed, will be discussed. The chapter will be concluded by discussing the impact of uncertainties on the KPIs used for the business case evaluation.

2.2.1. Uncertainty sources

Uncertainty in techno-economic parameters dominates the development and operation of an offshore wind farm, as is the case with hydrogen production. When the wind farm is integrated with electrolyzers, the uncertainties of both projects combine. Literature focusing on the uncertainty of an integrated asset is scarce. Therefore literature on the uncertainties of the offshore wind farm and electrolyzer will be identified separately.

Offshore wind projects encounter nine sources of uncertainty, according to [13] as mentioned in Section 1.4. Out of these, uncertainties in the wind resource, turbine performance, project costs, cost of money, and market revenues are the most relevant since they have the largest impact.

AEP uncertainty

Annual Energy Production uncertainties have been extensively studied in literature. [62] have identified 6 key variables influencing AEP and sub-categorizes them into wind resource and turbine parameters. The source of uncertainty on wind resource is the inherent stochastic nature of the wind resource, measurement errors during the site assessment process and modeling errors. Uncertainties on wake effects can arise from assumptions and simplifications of the modeling process, or by the stochastic nature of the wake movements [58]. Finally, uncertainties on surface roughness arise from the stochastic nature of the wave and tidal movements [62].

Uncertainties on the turbine are found on the power curve, thrust curves and plant performance. The power curve dictates the conversion of wind energy to electricity output, based on the wind speed. Power curves are usually provided by the manufacture and have been produced by both modeling and experimental measurements. Of course, measurements uncertainties along with different environmental conditions of the measurement and operation site lead to uncertainty in the exact form of the power curve [79].

Similar factors affect the thrust curve, which is important in operating the turbine, as it predicts the expected mechanical loads. Two examples to showcase the expected uncertainty bands can be seen in Figure 2.7. To conclude, the AEP uncertainty sources, plant performance uncertainty mostly refers to all the factors outside the wind resource, power and thrust curves, affecting the conversion efficiency or power production leading to uncertainties in farm output [51].

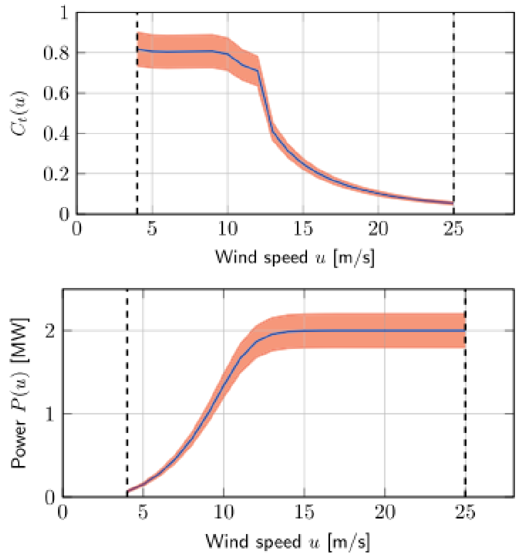

Figure 2.7: Thrust and power curve uncertainty, with a petrubance of 10%. *Reproduced from [62]*

CAPEX & OPEX uncertainties

The second main uncertainty source in offshore wind developments are CAPEX and OPEX. CAPEX can be uncertain due to a number of underlying variables, ranging from commodity prices of metals to the technological developments and scale up of wind turbine production. Therefore, estimating CAPEX during development phase comes with wide ranges of uncertainty.

Depending on the modeling level of detail, uncertainty on CAPEX can be considered as a lump sum on a per MW basis, or in individual components such as wind turbines. Ioannou et al. [43] estimated the standard deviation of CAPEX in based on different advisory reports and have calculated a Coefficient of Variation for CAPEX ranging from 0.04 to 0.2. This translates to a range of CAPEX of up to 20%, around its mean value. Evidently, when CAPEX is 70-80% of the total discounted projects costs, such deviations can make or break a project.

The same authors identified that OPEX can vary up to 30% compared to a deterministic value. Others have used much narrower ranges of uncertainty, with CAPEX and OPEX varying around 3 and 4% compared to their deterministic value, respectively. Another extensive dive into cost uncertainties by [54], considered bands of 10% around the nominal CAPEX and OPEX values. Finally, to incorporate uncertainty in installation & maintenance operations, Judge et al. [47] applied a stochastic sampling methodology in the weather time series, to account for uncertainties in access windows. In that manner, they were able to quantify the uncertainty in CAPEX & OPEX introduced by the weather.

Revenue uncertainties

The third major source of uncertainty significantly impacting the offshore wind farm business case relates to revenue, primarily driven by volatility in electricity prices. Although companies strive to reduce their market exposure by entering into Power Purchase Agreements with industrial consumers, a portion of electricity generation inevitably remains subject to market fluctuations.

Developers must account for historical volatility and simultaneously consider the broader and inherently uncertain evolution of the electricity market. However, systematic treatment of these market-related uncertainties remains scarce in literature. One notable exception is the study by [6], which incorporates market-price uncertainties through scenario analysis to evaluate the mean Net Present Value (NPV) of onshore wind across various European markets.

Ioannou et.al [42] quantify the effect of day-ahead price uncertainty on the profitability of a wind farm, using a techno-economic model. The day-ahead forecasts are based on statistical methods, like Geometric Brownian Motions and Autoregressive Integrated Moving Average. Both methods are common for forecasting stock prices. The uncertainty is introduced, through injecting uncertainty in the parameters used by the forecast methods. Thereby, the authors define 1000 different price-evolution pathways, which they later utilize to evaluate the farm's profitability. Several of the pathways can be seen in Figure 3.5.

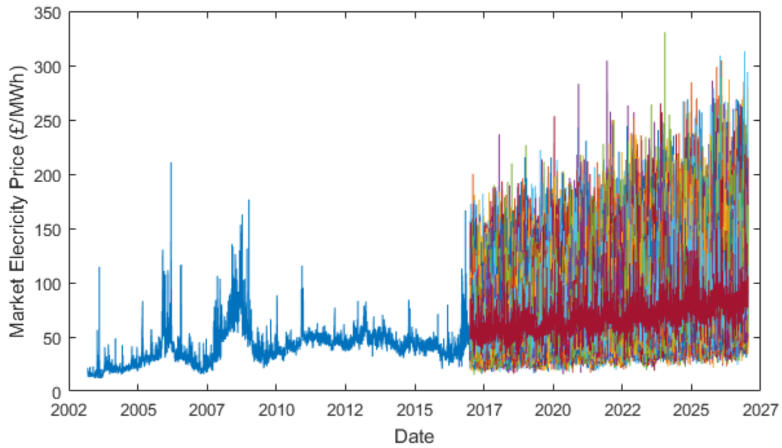

Figure 2.8: Uncertainty Quantification on the revenue side, visualized through different pathways. Taken from [42].

Finally, Caputo et.al [13] implemented Monte Carlo sampling, to generate different electricity price pathways and derive the NPV and IRR of a single floating wind turbine. Specifically, for each year they generated 100 different hourly scenarios based on Monte Carlo sampling of the ARIMA model parameters. This methodology resembles, the one proposed by [42]. Despite incorporating revenue uncertainties, all three studies fail to include them in a broader context, where cost uncertainties are present.

Financial parameters uncertainties

The final key uncertainty of an offshore wind farm is the financial parameters and mostly the Weighted Average Cost of Capital. As WACC is highly uncertain, especially due to the stochastic nature of interest rates which explicitly effect it, it is often identified as an uncertainty in literature. Specifically, [74] utilize three different scenarios of 3, 7, 10% interest rates to estimate the sensitivity of a wind farm's LCOE to it.

Due to uncertainties in the long-term financing of the projects, [47] varied the discount rate, a proxy for WACC, from 0-5%. A 10% variation of WACC around a nominal value was also proposed by [5]. Finally, [43] implicitly varied WACC, by changing the cost of equity and debt. It has to be noted that most authors considered the impact of WACC through sensitivity analysis or through scenario-analysis, but not through systematic uncertainty quantification with probability distribution functions.

Electrolyzer uncertainties

On the electrolyzer side, the key uncertainties concern the plant's CAPEX and OPEX, largely due to the novel application of Proton Exchange Membrane (PEMEC) or Alkaline Electrolysis (AEL) technology and the scale of the electrolyzers. Given that these technologies have not yet achieved widespread adoption or benefited from learning curve effects, the resulting projections encompass significant uncertainty. This has been demonstrated in Section 2.1.2 where the range of CAPEX for electrolyzers is between 359-1300 k € /MW.

Research by [9] on the uncertainty of green hydrogen production from onshore wind and solar has identified four key uncertainties. First, the cost of electricity which heavily influences OPEX, then the cost of electrolyzer which is considered as a beta-PERT distribution, the price of water through a triangular distribution and finally interest rates again through a triangular distribution. Expert opinion within Vattenfall and TU Delft supports that the degradation rate of the electrolyzer along with the expected lifetime are two key uncertainties influencing the CAPEX and OPEX of the project, along with the output. The rule of thumb is that every 40000 hours of operation, the stack loses 10% of its efficiency, but the exact number is not known [45].

On the revenue side, although merchant exposure is not considered—based on the assumption that a hydrogen market will not be fully developed by 2030, uncertainty persists regarding the pricing of Hydrogen Purchase Agreements (HPAs). This type of uncertainty could be handled through different HPA price scenarios, as proposed by [45].

2.2.2. Uncertainty Quantification methodologies

When the uncertain parameters have been identified, the next step is to define their distribution, in case of continuous variables. The distribution can be arbitrarily defined, but can also stem from experience. For example, if a large enough sample is present, a developer can define its own distribution based on observations. Variables which have a more stochastic nature or are influenced by numerous parameters could be best described by a normal distribution. For example, the Interest Rate Risk, describing the losses due to changing interest rates, can be described by a normal distribution [61].

In cases where a normal distribution would cause unphysical results, a truncated normal distribution can be fitted as done by [62] for the surface roughness, or a triangular or beta-PERT distribution as considered by [9]. Additionally, applying either a triangular or beta-PERT distribution is quite useful for variables such as CAPEX were a minimum, maximum and most likely estimate exist. Another approach by Richter et al. [62] is that instead of defying a distribution for the parameters, they defined a perturbation parameter ξ which follows a normal distribution $\xi_i \sim \mathcal{N}(\mu_i, \sigma_i)$. Therefore, this perturbation is inserted as an uncertainty in the different parameters.

Once the distributions have been defined, the next step is to propagate the uncertainties through the models. Various methodologies exist depending on the type of uncertainty and the type of the model. There are intrusive and non-intrusive methodologies based on whether they modify the model or the governing equation [70]. Non-intrusive methods do not modify the fundamental computational model, but rather treat as a black-box. In the case of a large and computationally expensive, such as the techno-economic model proprietary to Vattenfall, it is impossible to apply an intrusive method, as the relationships between the variables are not always described by straightforward relationships. Therefore, the methodology of uncertainty quantification will focus on non-intrusive methods.

Non-intrusive methods focus on sampling the variables systematically to cover the entire space of uncertainty, and are in general easier to implement. The model is run for every sample, and then the results are aggregated and post-processed. Therefore, the key to successful implementation is a correct sampling of the design space. The most relevant sampling methodologies when dealing with large sets of uncertainty in the context of technoeconomic modeling, are the Monte Carlo, quasi Monte Carlo and Latin Hypercube sampling.

Monte Carlo is extensively applied in literature and industry since it is easy to implement and is readily available in a lot of computational packages. Monte Carlo is based on using a random number generator to sample different points from all the probability distributions. Once the sampling has been complete, the model is run and its outputs are evaluated. This process is repeated numerous times until a convergence criterion is met, and then all the outputs are statistically aggregated. Monte Carlo is a simple yet powerful sampling approach, but its simplicity is also its main drawback, because the convergence is slower compared to other methodologies.

To solve the issue of slow convergence, the quasi Monte Carlo method has been introduced. The main difference compared to normal Monte Carlo sampling is that the samples are generated using a pseudo-random manner. The main advantage of quasi Monte Carlo is that for smooth sampling spaces, it can achieve faster convergence to regular Monte Carlo. The exact mechanism of convergence is out of the scope of this research, but for a reasonable sample the convergence rate of the quasi Monte Carlo from table 2.4 can be approximated to $O(n^{-1})$ which is much faster than the convergence rate of Monte Carlo.

The exact rate of convergence is problem specific and if the quasi Monte Carlo convergence is actually faster will be only ascertained computationally. On their research, [62] utilized Sobol sequences to generate the pseudo-random samples and calculated the error with respect to a quasi Monte Carlo approach with $N = 1 \cdot 10^8$ samples. As seen from Figure 2.9, quasi Monte Carlo is the optimal sampling strategy of the three considered, for two reasons. First, along with Sparse Grids has the fastest convergence rate and second compared to Sparse Grid, there are no requirements to calculate the grids before running the models.

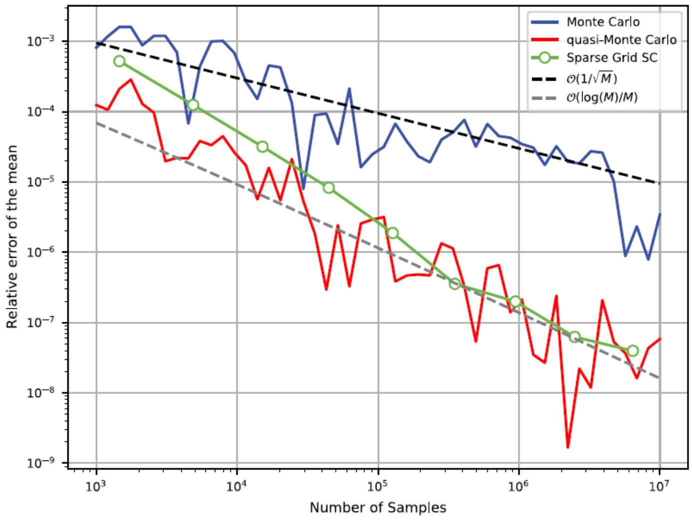

Figure 2.9: Convergence rate comparison between, Monte Carlo, quasi Monte Carlo and Sparse Grid methods. *Reproduced from [62]*

Method	Convergence Rate
Monte Carlo	$O(n^{-1/2})$
Quasi Monte Carlo	$O(n^{-(1-\epsilon)})$

Table 2.4: Monte Carlo and quasi Monte Carlo convergence rates, based on [35]

The final methodology applied for sampling the different probability distributions of the uncertain variables is Latin Hypercube Sampling (LHS). Latin Hypercube Sampling separates each probability distribution in N equal intervals, which are called strata. Then at random, one sample is drawn from single strata across all the uncertain variables and then the model is run for this sampling of the probability space [31]. The entire process is repeated until a convergence criterion is met. Through the stratification, LHS avoids clustering of points, which could happen with random Monte Carlo. For a limited number of samples, LHS is more efficient than normal Monte Carlo. But quasi Monte Carlo is more efficient than both LHS and normal Monte Carlo, if there are a few dominant variables or when all the variables are of relatively equal importance [71].

2.2.3. Impact of uncertainties on business case

Having covered the uncertainties and quantification methodologies discussed in literature, their impact on the business case will be presented. For business case evaluations, the four KPIs mostly are the NPV, IRR, LCOE and LCOH.

Applying uncertainty quantification of a floating offshore wind farm with an onshore centralized hydrogen production, showcased that by including uncertainties in costs items indicates that the project has a positive NPV only 34.35% of times and a LCOH P50 value between 14.25-14.50 $/kg [45]. These results, underscore the broad range of profitability outcomes when uncertainties are considered. Such studies can help decision makers to identify a project's risk.

Ioannou et al. [43] applied Monte Carlo analysis and compared the deterministic results utilizing only the mean value with those of the stochastic cases. They found an offshore farm's LCOE standard deviation is 21.8 €/ MWh with a mean price of 133.9 €/ MWh, again arriving at a broad range of economic outcomes. Given that range of LCOE, a project can be from barely feasible to totally non-economical, given electricity prices or subsidy schemes.

Richter et al. [62] applied the quasi Monte Carlo with 10^6 samples and defined sensitivity factors to assess the individual influence of the uncertain parameters in three different wind farms, Horn Revs 1, DanTysk and Sandbank. Through the use of box plots, they identified the influence on LCOE. The parameter and range selection is based on data from Vattenfall and shall be representative of real-world uncertainties. The box plots of Figure 2.10 indicate the impact of all uncertainties on the LCOE along with the individual impact, with the 50% of the results laying between 105 and 125 €/ MWh.

Heck et al. [30] integrated the results of Monte Carlo simulations for different generation technologies, as a risk premium. This risk premium is added to the nominal LCOE and allows for a fair comparison of technologies. For example, offshore wind had a higher nominal LCOE than coal plants, but when considering the higher risk premium that a coal plant might face, due to uncertainties in emission prices, they are almost at par with wind, which had a lower risk premium.

Caputo et al. [13] investigated the combined effect of uncertainties on component failure rates and efficiency, wind resource, investment costs, cost of capital and market prices, implementing Monte Carlo. The authors derived three possible market scenarios, where Scenario A presented a business-as-usual case, Scenario B assumed the model factor is set to reflect a 1% yearly increase in prices, while Scenario C a 1% yearly decrease.

The results indicate the sensitivity of the project's profitability to the market prices. The probability of achieving a negative NPV was calculated at 5.7% ,1.2% and 19%. This is a striking conclusion, since a 1% per annum reduction in market price leads to a 13.3% increase of probability for the project to prove unprofitable. On the other hand, a 1% per annum increase in prices, increases the prospects of profitability by 4.5%.

On the effect of electricity-price uncertainties, Ioannou et. al [42] identified that depending on the forecast model used, different NPV distributions are acquired, underlying the non-linear relationship between prices and project outcomes. Interestingly, they also identified that incorporating

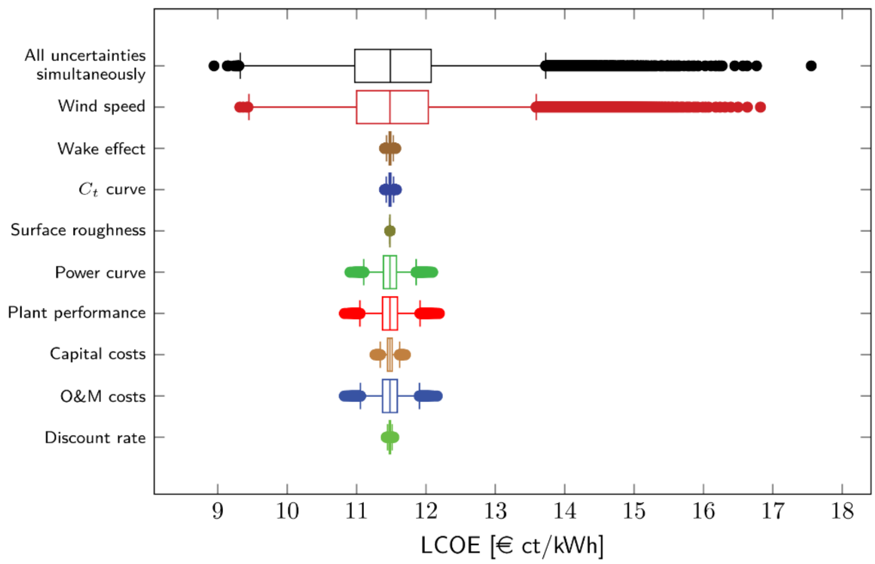

Figure 2.10: Box plots to visualize the combined and individuals effects on LCOH. The whiskers indicate the smallest and largest data values, while the dots the outliers. *Reproduced from [62]*

revenue uncertainty, increases the project's NPV by 11.7% compared to a deterministic market price consideration, in the case of an ARIMA model.

A comprehensive literature review on the topics of techno-economic analysis and uncertainty quantification of hybrid powerplants was conducted. The techno-economic analysis provides a deterministic view of the project and serves as the basis for uncertainty quantification. Most literature employs random sampling through Monte Carlo to propagate the uncertainties through the techno-economic model. The existing literature focuses extensively on uncertainties for offshore wind, mostly on the fields of wind resource, project costs and financial parameters uncertainty. Yet, uncertainty due to the unpredictability of the day-ahead electricity prices is underrepresented. The Monte Carlo approach for revenue uncertainty quantification proposed by Ioannou et.al [43] is promising to include revenue volatility in the hybrid plants assessment.

Literature identifies the importance of hydrogen and offshore wind synergies. Yet, there is limited research on the uncertainties faced by those hybrid solutions. Given their importance for the future energy system and the high degree of uncertainty, especially for the investment costs of the electrolyzer identified, the need to perform a study that includes cost and revenue uncertainties of an offshore farm with hydrogen is imperative.

3

Methodology Development

The aim of this Chapter is to introduce the methodology utilized for this research. The goal of the study is to assess how the uncertainties in the business case of an offshore wind farm are affected by the addition of a hydrogen plant. Section 3.1 introduces the techno-economic model required to evaluate the economic performance of the farm, the modelling algorithms utilized for the electrolyser revenues, along with the uncertainty quantification methodology. Next, Section 3.2 defines the key components constituting the offshore wind farm and the main sources of uncertainty relevant to it. Finally, Section 3.3 extends those definitions to the hybrid powerplant.

3.1. Modelling approach

3.1.1. Project timeline

The capacity to build an offshore wind farm is typically auctioned by government via competitive tenders. Developers submitting their bids either as request for subsidy or as a rent, payable to the government for the lease of the wind farm area. The developer with the best bid wins the tender and gains the right to develop in the tendered area.

Typically, the process to construct a wind farm from the announcement of the tendering process, until it is decommissioned can be seen in Figure 3.1:

1. **Tender Announcement:** The government announces the auction and the rules for participating in the auction.
2. **Bid Decision:** The developer considers the auction rules and based initial cost and revenue estimates decides whether to proceed with bidding for the project and if yes, the bid level. In this project-phase, there are supplier negotiations leading to initial quotes. These quotes help estimate some of the major costs, but are still uncertain.
3. **Final Investment Decision:** After a successful bid is placed, the company works towards the Final Investment Decision. After a successful bid, more clarity on the major costs is achieved, through supplier negotiations. The increased detail of the inputs allows to better estimate the project's economic performance. In case the project is still investable, FID is taken, marking the developers financial commitment to the project. Simultaneously, FID marks the **financial close** of the project, where all agreements are financially bound.
4. **Commercial Operation Date:** After a positive FID, the construction of the project starts. The construction period can last 2-4 years depending on site-specific parameters and the size of the

Figure 3.1: Development timeline of an offshore wind farm, under an auction scheme

project. The Commercial Operation Date marks the data where the construction is finished and the wind farm becomes operational.

5. **Decommissioning:** Once the wind farm reaches its end of useful life, the decommissioning of the farm begins. During decommissioning, the turbines can be removed and the site can be returned in its prior state, or the farm can be repowered to extend the lifetime.

The project considered in this work is placed before the bid decision, as this phase is government by the highest uncertainty during the development phase. Therefore, the highest relevance with an uncertainty quantification study is achieved.

3.1.2. Techno-economic model

The economic performance of the project changes as the project moves downstream the timeline. This is due to the addition of new information or more informed estimates for the different costs. Hence, it is necessary to deploy a techno-economic model that allows to take informed decision in every project stage. Developing a detailed technical and economical model is beyond the scope of the thesis, with the techno-economic model treated as a black-box. Nevertheless, the black-box approach requires a fundamental understanding of the model's inputs and outputs. In Sections 3.1.2 and 3.1.2 the technical and economic modelling of an offshore wind farm are described:

Technical Modelling

On the technical side, the parameters listed below are relevant to design wind farm that maximizes the economic performance. A brief description of the technical model for each is given:

1. **Wind Turbine:** The wind turbine size is already fixed in late development and the modelling focuses on the performance of the different turbine models under investigation, through modelling of the power curve.
2. **Site Conditions:** Important inputs for the optimal design of the farm are the wind, wave and seabed conditions. Wind climate is necessary to estimate the farm's AEP and to inform the layout of the turbines. Moreover, combined wind and wave data dictate the accessibility of the wind farm to perform installation and maintenance operations. Finally, the geophysical data are necessary input to the foundation design and layout optimization process of the farm.
3. **Layout Optimization:** A module sitting in the core of the technical model is the layout optimizer. The layout optimization algorithm is a Genetic Algorithm, with the objective function being either either maximization of energy production or maximization of the present value of energy production minus cable and foundation costs. The algorithm is based on the published works of Fischetti and Cazzaro [27] and [14].
4. **Internal & External Wake Losses:** Wake modelling is another integral part of the technical model. Wake losses can reduce the farm's power output up to 17.5% [8], depending on the layout and wind direction. Wake losses arise from the turbines of the wind farm, but also from external, neighboiring wind farms, giving rise to a phenomenon coined "wind-theft". Modelling the effect of wakes on AEP, through wake models, helps form better estimates for the AEP and thus revenues.

5. **Cable Sizing, Routing & Electrical Losses:** To connect the wind turbines with the offshore substation, inter-array cables are required. Based on technical characteristics and costs of the available cable options, the technical model optimally places the turbines in strings[1]. This optimization impacts the installation cost of the cables. Once the cables are properly sized and routed, the expected losses of the inter-array cables are calculated. The losses determine the export capacity of the wind farm.
6. **Offshore & Onshore Substations** On the electrical side, the technical model assists in the calculation of losses induced by the electrical infrastructure of the offshore and onshore substations. Additionally, it calculates the expected weight of the foundations and topside, based on the rated power and the equipment requirements. The foundation weight of the topside is relevant for the installation and manufacturing cost.

All in all, the above six functions of the technical model are utilized to derive an optimal layout, with sized cables and the estimation of the Annual Energy Production, accounting for wake and cable losses.

Economic Modelling

The technical design of the wind farm informs the costs and revenues of the project. Therefore, an economic model that integrates the construction, operation & maintenance costs, and revenues is utilized, to test whether a bid decision can be taken. The key components of the economic model are:

1. **Capital Expenditure:** Capital Expenditure (CAPEX) is all the costs incurred during the farm's construction. CAPEX is closely related to the engineering choices, as depicted in the technical model of the wind farm. The key construction costs are related to:

   (a) Wind turbine procurement
   (b) Transport & Installation of wind turbines
   (c) Foundation procurement
   (d) Foundation installation
   (e) Inter-array cabling procurement
   (f) Inter-array cabling installation
   (g) Construction management
   (h) Project management
   (i) Offshore & Onshore substations
   (j) Offshore export cable
   (k) Contingency budget

   Capital Expenditure estimation pre-FID, is based on a combination of cost-modelling equations (See Section 2.1.1), current quotes or extrapolation of historic supplier quotes. Multiple costs have to estimated, since pre financial closure, prices are not contractually fixed. Estimates for large cost items are performed by subject-matter experts with an overview of project and market conditions.
2. **Operational Expenditure:** Operational Expenditures (OPEX) are all costs incurred to keep the wind farm operating. Since OPEX uncertainties are not part of the study, but OPEX modelling is performed in FEPM and the main items included in the OPEX are presented below:

   (a) Balance of Plant and Grid maintenance
   (b) Logistics & Offshore
   (c) Maintenance investments

[1]Arrangements of wind turbines that are connected with the same cable

   (d) Personnel costs
   (e) SCADA and communications
   (f) Service of the wind turbines
   (g) Site facilities

   Estimating OPEX pre-bid requires detailed insights into the operation of a wind farm, the expected failure rates, provisions for maintenance investments, vessels and personnel costs. OPEX modelling is performed by a specialized team, which feeds the inputs to the economic model. In nominal cash flows, OPEX is comparable to CAPEX, but since OPEX is spread over the farm's lifetime, its contribution is about 25% in the total discounted costs.

3. **Electricity Market Model:** To determine the annual day-ahead revenues pre-bid, an electricity market model is utilized. Based on the forecasted day-ahead price and AEP predicted by the technical model, revenues can be estimated.

   The electricity market forecast is affected by six different factors; (a) the speed of the energy transition (b) the extent of government intervention (c) the expected developments in fuel and carbon pricing (d) the development of the generation-technology costs, (e) the forecasted electricity demand and (f) weather correlation.

   The combinations of these factors can yield different scenarios, with each forecasting a different development of the day-ahead prices. Since some factors are correlated, three forecast scenarios are derived, based on the data provided by the external market-consulting firm Aurora Energy Research. The three scenarios are high, central and low, with each describing a fundamentally different development of the market. None of the scenarios is given a higher weight by Vattenfall, but for the scope of uncertainty quantification, the central scenario is considered as the most probable.

   The central scenario prescribes strong renewable penetration, demand increase due to more electrification (and development of significant electrolysis capacity). These factors lead to moderate day-ahead prices. The day-ahead data provided by Aurora extend up to 2050. However, the lifetime of the farm extends beyond that. Therefore, from 2050 onwards, a repetition of the year 2050 is applied to cover the price-data gap.

4. **Key Performance Indexes:** The final step of the economic model is to calculate the KPIs required to evaluate the project's business case. The KPIs utilized are described in the Financial Analysis part of Section 2.1.4. Specifically:

   (a) Levelized Electricity Cost (LEC), which is an internal notation for LCoE. The LCOE BEIS notation is used, as defined in Equation 2.4.
   (b) Internal Rate of Return, as defined in Equation 2.2
   (c) Net Present Value, as defined in Equation 2.1.

   The discount factor d used is always equal to WACC, reflecting the cost of capital.

3.1.3. Dispatch optimization

The techno-economic model is used to derive the costs and revenues of an offshore wind farm. For the wind farm the revenue derivation is straightforward, based on AEP and the day-ahead price. However, in the case of a hybrid powerplant with an offshore farm and an electrolyser, a decision on when to produce electricity, hydrogen or both, has to be made. These problems of deciding when to produce are characterized as **dispatch decision**.

This decision is made by the dispatch optimization algorithm, which solves a Mixed Integer Linear Program (MILP). The integer part of the problem arises from the electrolyser, which is either producing at full-capacity or is off. Hence, its operational state can be described through an integer. To make the decision, the algorithm reads four inputs related to the wind farm power output, the electricity and hydrogen prices and finally the electrolyser's efficiency. Using the inputs, while meeting some technical constraints, the dispatch optimizer outputs the revenues of the hybrid park.

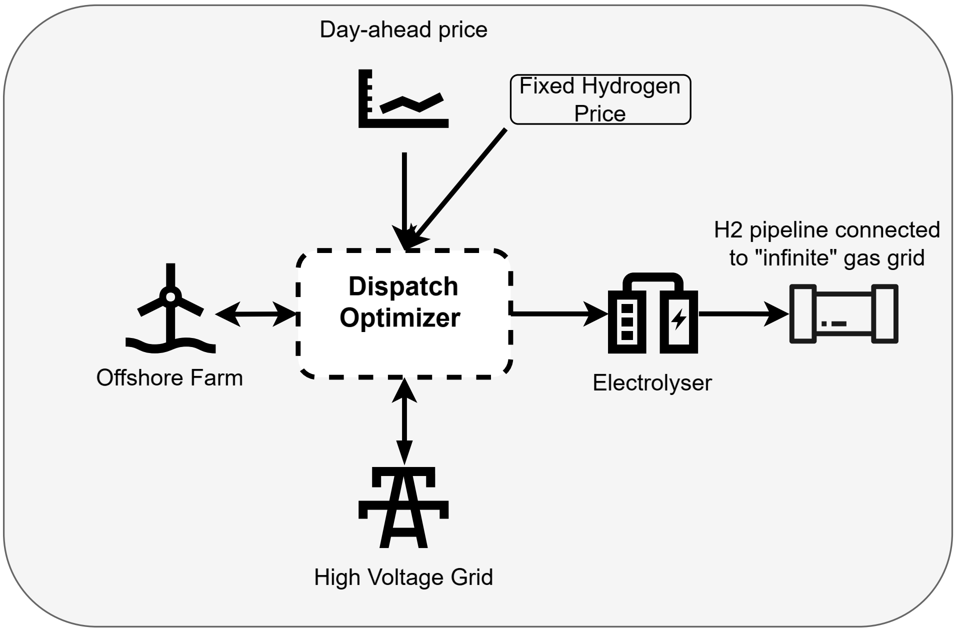

Figure 3.2: Dispatch Optimization Schematic

Inputs

The day-ahead market price, hydrogen delivery price and electrolyser efficiency are the three inputs, necessary to calculate the break-even point between electricity and H2. If the electricity price is below the break-even it beneficial to produce H2 rather than electricity. A rudimentary demonstration of the dispatch decision between electricity and hydrogen, including calculations, can be found in the Appendix B.

1. **Wind farm power output:** The optimizer reads the hourly output of the wind farm at the metering points after all losses. This is the available power which can be either converted to H2 or exported to the grid.
2. **Day-ahead market price:** The optimizer reads the day-ahead electricity prices, to decide when it is optimal to produce hydrogen and when to export electricity.
3. **Hydrogen delivery price:** The optimizer can take into account the price at which hydrogen is traded. Since a hydrogen market does not exist, the delivery price and volume is agreed via Hydrogen Purchase Agreements (HPAs). For this work an HPA with a steady price of 4 €/kg has been assumed.
4. **Electrolyser efficiency:** Another input to the dispatch decision, is the electrolyser's efficiency. The efficiency along with the electricity and hydrogen prices determines the break-even point.

Technical Constraints

In addition to the inputs, the dispatch decision has to respect four technical constraints. Each constraint is analyzed individually below:

1. **Grid import & export capacity:** The export capacity to the grid is limited by the agreement between the wind farm operator and the TSO, and the electrical infrastructure of the hybrid

plant. The import capacity is utilized to operate the electrolyser when the farm's power output is not sufficient. The export capacity of electricity is likewise limited by agreements between the asset owner and the TSO.

2. **Electrolyser stack capacity:** The electrolyser has a physical constraint on the maximum hydrogen mass that can be produced per hour.
3. **Electrolyser ramp up & down limits:** A PEM electrolyser has specific ramp up and down limits, that have to be respected for safe operations. Since this limits are typically in the order of seconds, and the granularity of the optimizer is hourly, the dynamics of ramp up and down cannot be captured. Therefore, these constraints will not be active here.
4. **Power balance:** The power balance in the system between, wind production, grid export or import, losses and electrolyser consumption has to be always respected.
5. **Hydrogen off-take agreements:** A Hydrogen Purchase Agreement will typically provision that the hybrid powerplant delivers at least a minimum hydrogen quantity or a steady hydrogen output. For this work, it is assumed that the electrolyser is connected to an "infinite" gas grid. Consequently, hydrogen flows into a gas grid, without the need to meet any constraints regarding off-take, as presented in the schematic of Figure 3.2. Hence, this constraint is not active.

Outputs

1. **Hydrogen production:** After the dispatch optimization has been successfully completed, the hydrogen production is exported.
2. **Electricity exchange with grid:** Similarly, the net electricity exchange with the grid is calculated.
3. **Revenues:** Finally, the revenues from sales of both electricity and hydrogen are calculated. The revenues are then input in the techno-economic model, to evaluate the economics of the hybrid powerplant.

3.1.4. Uncertainty Quantification

The techno-economic model used for the offshore wind farm and hybrid powerplant and the dispatch optimizer leveraged for the revenues of the hybrid plant have been described. These models allow to derive the economic KPIs to evaluate the business cases.

To incorporate uncertainties related to the outputs and to investigate their impact on the project KPIs, an uncertainty propagation methodology is employed. Employing a Monte Carlo approach, the distribution of the input parameters are randomly sampled and then propagated through the techno-economic model, without requiring changes to the core model. Specifically, the methodology to probabilistically assess the business case of an offshore wind farm under the presence of uncertainty is summarized in the following 5 steps and in Figure 3.3.

1. **Step 1:** Each input that is associated with uncertainty is described by a Probability Distribution Function (PDF). More details on the derivation of the distributions can be found in Sections 3.2.3 to 3.2.6. All uncertainties follow a triangular PDF to represent a central, most probable scenario which is the mode of the PDF and the two most extreme values, corresponding to low and high scenarios.
2. **Step 2:** Once the uncertain inputs are defined, Monte Carlo sampling is applied. Monte Carlo samples the PDF in a random manner, through a random-number generator. The sampled inputs are aggregated in a vector, which is then concatenated with all the deterministic inputs of the techno-economic model.
3. **Step 3:** Using the vectorized inputs, the techno-economic model is called and it outputs the KPIs for each set of inputs. The simulation can be run in-parallel to accelerate the computation.

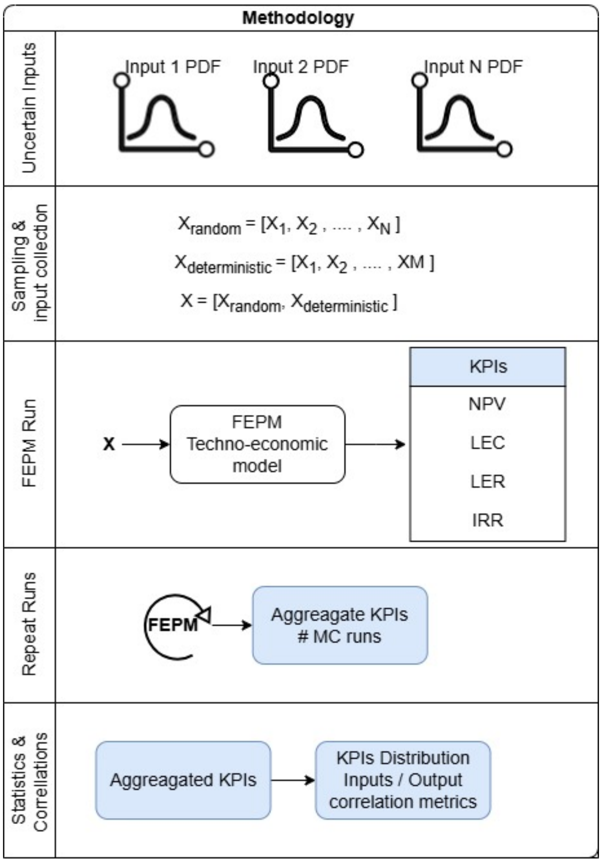

Figure 3.3: Methodology Overview

4. **Step 4:** Random sampling, vectorization of inputs and FEPM runs is repeated until, the simulations reaches the predefined level of Monte Carlo runs.
5. **Step 5:** The KPIs produced from all Monte Carlo simulations are aggregated and their statistics are calculated.

The key statistics calculated for each KPI in Step 5 are:

1. **Probability of Exceedance (P10, P50, P90)**: The probability-of-exceedance values indicate the value, above which 10, 50 or 90% of the data lies. For example, a P90 value of LEC = 45 € /MWh, means that 90% of the outcomes of the Monte Carlo lead to a LEC value of at least 45 € /MWh.
2. **Probability Density Function**: For each KPI, a probability density function is fitted to the data, using a kernel density estimation. This helps visualize the distribution and the risk-profile of the project.

Calculating the probabilistic values along with the shape of the distribution provides a metric for how the input uncertainties translate to measurable business case risks. If the probability-of-exceedance values are close together, the distribution of outcomes is narrow leading to a robust project. Additionally, if the estimated PDF is fat-tailed, outliers can appear more frequently, compared to a normal distribution. Therefore, the statistics and the shape of the PDF have to be considered simultaneously.

3.1.5. Convergence Study

Step 4 of Section 3.1.4 mentions that the Monte Carlo simulation stops only if it reaches a predefined number of iterations. In general, the more iterations, the higher the accuracy of the stochastic variable estimate. Precisely, the relationship between the accuracy and the number of iterations is the convergence rate. The convergence rate of a problem cannot be known a-priori. Consequently, a convergence study is performed to set the number of iterations required to meet a certain level of accuracy.

Two methodologies, based on the convergence analysis presented by [18] are applied. The first relies on the rolling average of the iterations. Since this is the average of all samples up to the k-th simulation (Equation 3.1), the solution will tend to converge to a steady value, equal to the median.

$$MA_k = \frac{1}{k}\sum_{i=1}^{k} LEC_i, NPV_i \tag{3.1}$$

The second convergence monitoring methodology is based on the standard error of the simulation. The standard error measures the accuracy with which a sample distribution represents a population. The smaller the standard error, the more precise the estimate. The standard error of an independently drawn sample $x_1, x_2, ..., x_n$ is defined in Equation 3.2. Because the standard deviation of the population is not known, it is often estimated by the standard deviation of the sample. Consequently, Equation 3.2 transforms to 3.3:

$$SE = \frac{\sigma}{\sqrt{n}} \tag{3.2}$$

$$SE \approx \frac{\sigma_x}{\sqrt{n}} \tag{3.3}$$

where :

SE	Standard Error
σ	Standard Deviation of population
n	Sample size

Because the uncertain inputs do not impact every KPI on the same manner, the convergence of at least two KPIs has to be monitored to infer the simulation's convergence. The two elected metrics are the NPV and IRR. Convergence of these two metrics is monitored through an "eyeball" test, for the rolling average. The convergence of the NPV and LEC standard error is monitored through a target accuracy. For NPV convergence, this accuracy is set at 10^{-1} and for IRR at 10^{-2}. With this accuracy, NPV can be estimated within 1 M € and IRR within 0.01 %. Essentially, the standard error is the uncertainty injected by the sampling method in the outputs. With the mean NPV and LEC values observed, this uncertainty is expected to be less than 1% and is within the acceptable limits.

The convergence rate of Monte Carlo is $O(\sqrt{n})$, hence reducing the target standard deviation error by one order of magnitude, requires increasing the number of samples with the square. Aiming for a low standard error or smooth rolling-average curve, involves a trade-off between accuracy and computational time. Errors below 10^{-1} or 10^{-2} rapidly increase the computational time and do not add value to the analysis, especially for risk analysis purposes, as a deviation in NPV of less than 1M M € will not significantly impact the decision to invest in a project.

3.1.6. Spearman Correlation Index

Step 5 of Section 3.1.4 is the statistical post-processing of the results. The results of the thousands of Monte Carlo simulations can reveal insights about the parameters that constitute the main uncertainty drivers. To identify the uncertainty drivers, a metric that correlates the variability in an input with the corresponding variability in an output has to be deployed.

The Spearman correlation index is the appropriate metric to derive these input-output correlations, as it allows to rank the inputs with respect to their impact on the output. For each input variable, the Spearman correlation coefficient is applied based on the formula 3.4.

$$r_s = \frac{cov([R[X]R[Y])}{\sigma_{R[X]}\sigma_{R[Y]}} \tag{3.4}$$

where :

X	Input variable
Y	Output variable
r_s	Spearman coefficient
$R[]$	Ranking of variables
$\sigma_{R[]}$	Standard deviation of X's rank
cov	covariance between X and Y ranks

The Spearman correlation coefficient assesses how well the relationship between two variables can be described using a monotonic function. The closer r_s is to ±1, the higher the correlation of this parameter with the variation in the output. Among the inputs, the one with the higher Spearman value r_s exhibits the strongest correlation. Therefore, by sorting the inputs based on their Spearman value, the main uncertainty drivers.

As the Spearman correlation is a statistic metric, its statistical significance is calculated through the p-value. The p-value is a measure of the significance of the r_s value and can inform whether the observed value is due to chance, or true correlation is observed. Only Spearman coefficients for inputs with a p-value lower than 5% are retained as statistically significant.

3.2. Offshore wind farm

With the techno-economic model and uncertainty quantification approach established, this section firstly establishes the technical description of the offshore wind farm. The same offshore wind farm is utilized for both the baseline and hydrogen case. Secondly, the derivation of the company-wide cost of capital is presented. Finally, the definition of all uncertainties relevant to the baseline case is discussed. The uncertainties are separated on three different categories, starting with electricity-market uncertainties, commodity price uncertainties and finally uncertainties related to the cost of vessel operations.

3.2.1. Technical description

The project considered for the baseline case is representative of a standalone wind farm with an expected **Commercial Operation Date in 2031** and without any system integration additions. Following the latest tender rules by the Dutch RVO for sites Ijmuiden Ver Alpha and Beta [1] and TenneT's 2GW standard [7], it is assumed 2 GW will be a capacity common in fixed-bottom projects across the North Sea. Therefore, the export capacity of the farm is set at 2 GW.

On the technical side, turbines with a rated power P_{rated} of 23 MW will be installed, with their hub measuring 162 m above the mean sea level. 105 turbines are to be placed, leading to a park nominal capacity of 2415 MW. The farm's nominal capacity is 20% higher than the transport capacity of the export cable, as result of the overplanting study. Since wake effects, transmission losses and turbine availability reduce the power delivered to the grid, increasing the installed capacity (overplanting) leads to full utilization of the export cable's capacity.

Regarding site conditions, the mean wind speed identified through the metocean studies is 10.14 m/s, with a South-West prevailing wind direction. The development site has a distance to shore of around 50 km. The distance between the offshore substation and the onshore landing of the export cable is 50 km. The offshore substation boasts 4 transformers with a rated apparent power of 462 MVA each, and the High Voltage Direct Current export cable is rated at 525 kV. The main technical characteristics of the wind farm are summarized in Table 3.1.

Parameter	Value	Unit
Distance to shore	50	km
Mean wind speed	10.14	m
P_{rated}	23	MW
Hub height	162	m
# of turbines	105	-
Park $P_{nominal}$	2100	MW
Inter Array Cable	132	kV
Offshore Export Cable - HVDC	525	kV
Offshore Substation Transformers	462	MVA

Table 3.1: Summary of base case technical parameters

3.2.2. WACC derivation

To derive the project's Net Present Value, the Weighted Average Cost of Capital has to be calculated, as defined in Section 2.1.6. WACC depends on three parameters: debt-to-equity-ratio, cost of debt and cost of equity, which will be analysed separately.

Starting with the debt-to-equity ratio, the project reflected on the baseline case is financed on-balance sheet, following Vattenfall's common strategy. Consequently, the debt-equity ratio of the project is inherited from the mother company. In Q1 2025 Vattenfall reported its debt-to-equity ratio at 40:60 [76]. Moving on to the cost of debt, it is calculated based on Equation 2.6. Vattenfall publicly reported that its average interest rate on outstanding debt stood at 3.6% for Q1 2025 [76]. Since Vattenfall holds most of if its debt in corporate bonds, the interest rate reflects the bond yield.

The final parameter necessary to calculate the cost of capital, is the cost of equity, which is derived from the Capital Asset Pricing Model, as introduced in Section 2.1.6 and Equation 2.7. Beta has been estimated from the published β values of 6 major European utilities owning portfolios of renewables similar to Vattenfall (Table A.5). The risk-free-rate R_f has been taken as the overnight euro rate currently around 2.6%. As offshore wind is a globally attractive investment, the MSCI World Index is used to estimate the market premium R_m. The annualized returns of the index over 40 years are 8.1%, therefore $R_m = 8.1\%$. All CAPM inputs are summarized in table 3.2.

Parameter	Value
β	0.87
Risk free rate R_m	2.7%
Market Risk Premium R_f	8.1%

Table 3.2: Summarizing table for inputs of the Capital Asset Pricing Model

Based on the cost-of-debt, cost-of-equity, gearing ratio assumptions and assuming a tax rate of 20% the company-wide WACC is calculated at 6%, based on the formula. To reflect the estimation of the cost-of-equity the WACC value is inflated by an additional 1% to a final value of 7%. All the inputs going into WACC calculation can be seen in Table 3.3.

Based on an 7% WACC, a 1% risk premium is added, to arrive at a Direct Hurdle Rate of 8%/ This value is in line with the recent reports by RWE. A DHR of 8% reflects the ongoing risk of offshore wind, but also a trend of de-escalation of risks, for an FID around 2028 [2].

[2]The Direct Hurdle Rate is calculated for use of this thesis, based on the writer's assumptions and does not reflect Vattenfall's DHR

Parameter	Value	Unit
Cost of Debt	3.6	%
Cost of Equity	8.1	%
Gearing Ratio	40:60	-
WACC from formula	6	%
Risk Premium	1	%
Project WACC	7	%

Table 3.3: Inputs for cost-of-capital calculations

Despite overall uncertainties in all WACC inputs and WACC being an uncertain input in some published works ([43], [47]) a fixed cost of capital between before a bid decision is assumed. For a project to have moved to a successful bid, WACC will stand at a level that will allow the project to move forward with a certain degree of certainty. Additionally, Vattenfall has a strong credit rating and because it finances projects on-balance sheet, capital costs tend to stay stable, compared to project-financed developments, which are more sensitive to macroeconomic changes. This is why, despite possible uncertainties, WACC is considered fixed, in the timeframe the project is examined.

3.2.3. Revenue uncertainties

The uncertainty on the electricity market is quantified based on the expected price difference between the central and low market scenarios, thoroughly described in Section 3.1.2. Based on the price deviation of the two scenarios, a symmetric uncertainty band around the central scenario is defined. The annualized price forecast in nominal terms and the uncertainty range can be seen in Figure 3.4.

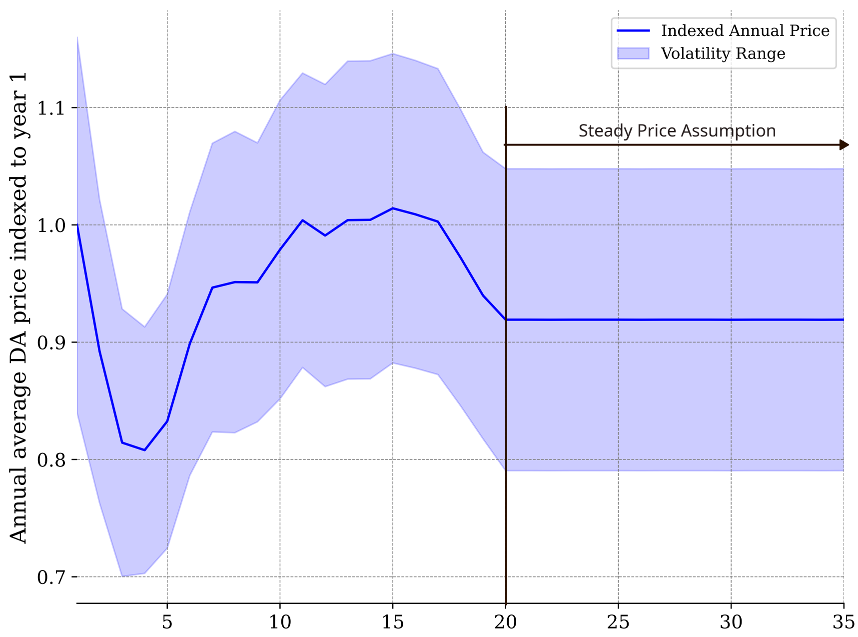

Figure 3.4: Annual day-ahead price forecast and the associated uncertainty bands. The prices are in nominal terms, i.e. not adjusted for inflation.

Based on the price uncertainty bands of Figure 3.4, a triangular distribution is defined for every year where :

1. The distribution's mode is the price forecast by the central scenario

2. The minimum value is the price corresponding to the low uncertainty band
3. The maximum value is the price corresponding to the high uncertainty band

Once the distributions are defined, 10,000 Monte Carlo samples are performed. Therefore, for each sample a random price is picked for every year, leading to 10,000 different revenue "pathways". These pathways reflect the impact of the day-ahead price uncertainty on the revenue of the wind farm. 10 out of those 10,000 realizations have been randomly drawn and are presented in Figure 3.5.

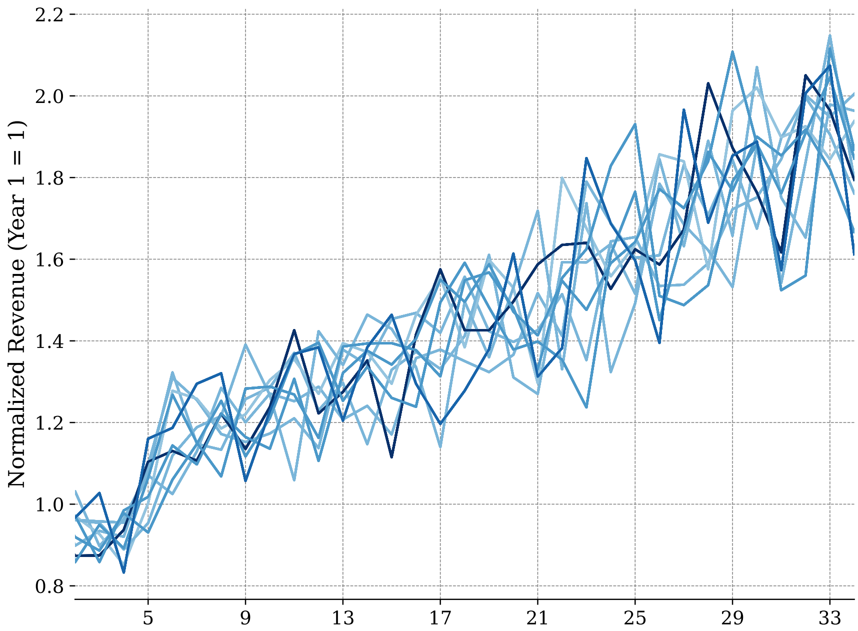

Figure 3.5: 10 out of the 10,000 revenue pathways defined using Monte Carlo simulations. Values are non-dimensionalized against the revenue predicted for Year 1 by the deterministic simulation.

3.2.4. Commodity price uncertainties

Commodity price volatility constitutes another significant source of uncertainty, as prices of key inputs, such as metals and fuel, remain highly variable until the project's financial close at the Final Investment Decision (FID). Throughout the development phase, commodity-price uncertainty remains a critical determinant of project feasibility, and must therefore be quantified, taking the following approach:

- Datasets with forecast scenarios for steel, aluminum, copper and marine gas oil are utilized to establish price ranges for the commodities. These datasets are provided by external consulting parties, active in the fields of commodity trading. Typically, there are three different scenarios pertaining to the development of the commodity, low, central and high.
- The exposure of the wind turbine, foundations, offshore substation, inter-array cabling is calculated. The exposure gives the sensitivity of the cost w.r.t to the variation of the underlying commodity and is primarily based on the commodity mass utilized in each component [3].
- Based on the exposure and the expected variation in the commodity prices, triangular distribution for the CAPEX of each considered components are defined. Always, the central scenario is considered the most probable, thus the distribution's mode is equal to the central price scenario.

[3]It is assumed that variations in raw-material price are passed directly to the buyer, without affecting fabrication or other costs.

Below, a more detailed calculation of the exposure to each commodity category is presented:

Steel

Steel constitutes the principal raw material in an offshore wind farm, exerting substantial influence on the cost of turbine towers, monopiles and the topside and foundations of offshore substations. For this work, raw S275 structural steel is considered as the main steel used in a wind farm.

Using the weight of raw steel, the total cast of the raw material, and the total cost of the entire component, the exposure can be calculated. For example, raw steel amounts to 17.8% of total cost, in a single foundation. Therefore, a ±25% uncertainty on S275 price, will lead to a ±4.4% deviation of the foundation cost. Applying the same methodology to the other steel-intensive components, leads to the uncertainty bands present in Table 3.4. Evidently, foundations have the highest exposure to raw-steel because it is a greater cost component of the total cost, compared to tower & nacelle and offshore substation, with raw-steel price constituting less than 5% of total cost.

Component	Lower Limit	Upper Limit
Foundation	-4.4%	+4.4%
Tower & Nacelle	-1.2%	+1.2%
Offshore Substation	-0.9%	+0.9%

Table 3.4: Price risk bands due to S275 price-uncertainty for major steel-intensive components

Aluminum and Copper

While steel is the most-utilized metal on a wind farm, aluminum & copper are two key metals primarily used in the inter-array cables. The uncertainties on the aluminum price is estimated between -15.3% and +19.2% and on copper price between -12.2% and +18.75%.

Based on the aluminum copper, mass breakdown for each cable, the uncertainties are aggregated in a single value. According to the calculations presented in Table 3.5

Component	Lower Limit	Upper Limit
Inter-array Cable - Aluminum	-0.4%	+0.5%
Inter-array Cable - Copper	-0.2%	+0.4%

Table 3.5: Price risk bands due to uncertainties in aluminum and copper for IAC

Marine Gas Oil

The final external source of commodity uncertainty considered in this work is the price of Marine Gas Oil (MGO). Marine Gas Oil is an essential input to the ships operating during the Transport & Installation and Operations & Maintenance phase. Marine Gas Oil is a derivative of heavy-oil and thus exhibits large price swings.

3.2.5. Vessel Cost Uncertainties

The extent of the uncertainties impacting vessel costs depends mostly on the contractual agreements for chartering them. According to [20], the most typical chartering arrangement for offshore wind is time chartering. In a time charter the vessel is chartered pro rate. The ship owner pays the capital charges and operating costs, while the charterer pays the voyage trips (port fees, fuel costs and canal dues).

Day rate & fuel cost uncertainty

During a time charter, the charterer covers the fuel costs, with the pre agreed daily rate excluding fuel costs. Therefore, the total cost for a vessel-day is given by equation :

$$C_{\text{vessel}}\left[\frac{\text{EUR}}{\text{day}}\right] = R_{\text{day}}\left[\frac{\text{EUR}}{\text{day}}\right] + Q_{\text{fuel}}\left[\frac{\text{tonne}}{\text{day}}\right] \times P_{\text{fuel}}\left[\frac{\text{EUR}}{\text{tonne}}\right] \tag{3.5}$$

where :

C_{vessel} **(EUR/day)** : Total vessel cost per day.

R_{day} **(EUR/day)** : Contracted day rate, covering base hire, crew and capital charges, and routine operating expenses.

Q_{fuel} **(tonne/day)** : Vessel's fuel consumption rate, i.e. tonnes of MGO burned per day.

P_{fuel} **(EUR/tonne)** : Unit price of Marine Gas Oil.

Based on the vessel day-cost for a time-charter (Equation 3.5), three key sources of uncertainty can be identified. First, is the day rate R_{day}, which can be contractually bound for the chartering duration. Nonetheless, when evaluating T&I expenditure in the development phase, it remains an unknown and with great variability, as found in Section 2.1.1. Secondly, the fuel consumption Q_{fuel} of the vessel can only be known ex-ante, but it is a crucial parameter to estimate the total fuel costs. Thirdly, the price of fuel P_{fuel} is subject to market fluctuations, as discussed in Section 3.2.4.

Table 3.6 breaks down the uncertainty per vessel type and construction phase. For example, the uncertainty sources for each vessel participating in the installation of inter-array cabling are analyzed separately.

	Vessel	Parameter	Lower Limit	Upper Limit
IAC Installation	**Inter-array cable burial vessel**	Mechanical Burial Day Rate incl. fuel price uncertainty	-12%	36%
		Jetting Burial Day Rate incl. fuel price uncertainty	-12%	36%
		Fuel Consumption	-20%	20%
	Inter-array cable lay vessel	Fuel Consumption	-20%	20%
		Day Rate incl. fuel price uncertainty	-14%	41%
	SOV	Fuel Consumption	-20%	20%
	Post-lay survey	Fuel Consumption	-20%	20%
	Preparation	Fuel Consumption	-20%	20%
	Protection System	Fuel Consumption	-20%	20%
	Cable Crossing	Fuel Consumption	-20%	20%
WTIV	**Wind Turbine Installation**	Day Rate	-10%	20%
		Fuel Consumption incl. fuel price uncertainty	-49%	91%
CII	**Monopile Installation**	Day Rate	-10%	30%
		Fuel Consumption incl. fuel price uncertainty	-49%	91%
		Hydraulic Hammer	-20%	20%
CM	**CTV for SOV Support**	Fuel Consumption incl. fuel price uncertainty	-20%	20%
	SOV	Fuel Consumption incl. fuel price uncertainty	-49%	91%

Table 3.6: Day rate, fuel consumption and fuel costs uncertainties for main vessels participating in the laying of the Inter-array cabling, installation of wind turbines, installation of monopiles and construction management. The uncertainty ranges have been defined based on expert knowledge regarding day-rates and fuel consumption. The fuel-price uncertainty is based on forecasts for Marine Gas Oil price. The fuel-price uncertainty is aggregated in either the day rate or fuel consumption uncertainty

Adverse Weather Downtime

The second factor influencing the vessel cost is the total number of charter days. Assuming the duration of the load cycles can be accurately estimated based on past experience, the required number of vessel-days is subject to a stochastic source of uncertainty. That is the Adverse Weather Downtime (AWD). Adverse Weather Downtime is caused by the inability to access the site or perform works, in times when the significant wave height or wind speed exceed the allowable limits of the vessel.

Consequently, vessels are hired with a buffer to account for AWD. AWD is specific to the individual site and is influenced heavily by the distance to shore, local metocean conditions and other environmental considerations, like icing formation.

Estimating AWD is a specialized task requiring knowledge of the accessibility and workability windows, i.e. the metocean conditions that allow for safe approach and performance of works. To calculate the former, data on the significant wave height and wind are required. To calculate the latter, the operational envelope of the vessel and crew, along with other safety related parameters have to be estimated.

Due to the complexity of the task, internal estimates have been leveraged to derive a stochastic range for AWD. The impact of AWD is quantified in Table 3.7 as a triangular distribution with its mode being the nominal availability for each vessel type.

Vessel Function	Lower Limit	Upper Limit
Monopile Installation	-11%	+22%
Secondary Steel Installation	-11%	+22%
Barge	-11%	+22%
Wind Turbine Installation	-7%	+22%

Table 3.7: Adverse Weather Downtime. For each vessel, a triangular distribution around the nominal availability is defined based on internal simulations. The uncertainty bands for Adverse Weather Downtime are project-specific and correspond only to the project considered on the thesis.

3.2.6. Construction & Project management cost uncertainties

The final sources of uncertainty identified are construction and project management costs. Construction management is performed during the installation phase of the wind farm and focuses on executing the construction schedule, coordinating vessel mobilization, weather windows, and contractor crews. Project management, refers to the activities carried out before the COD and has a broader scope compared to construction management.

During construction management vessels are utilized to monitor and coordinate the construction progress. Consequently, the main source of uncertainty are the vessels, and specifically the Service Operation Vessel (SOV) and the Crew Transfer Vessel (CTV) which is supportive to the SOV. Fuel consumption and fuel price uncertainty of the respective vessels are included in the construction management analysis, with the uncertainty range presented in Table 3.6.

While construction management is dominated by vessel costs, project management is mostly influenced by personnel costs. Therefore, the highest uncertainty is the personnel requirements and the expected payroll costs. The total cost of Project Management is modelled as a lump-sum payment and uncertainty is added on top of the sum, based on internal expert estimates. Usually projects tend to run over budget, so this is reflected on the triangular distribution of the project management costs, which is skewed towards the higher end. The lower and upper limits of the project management uncertainty can be seen in Table 3.8.

Project Management	Lower Limit	Upper Limit
Lump Sum Costs	-3%	7%

Table 3.8: Project Management cost uncertainties. Uncertainties are defined based on expert opinion.

3.3. Hybrid powerplant

The target of the thesis is to investigate whether H2 integration in an offshore wind farm can reduce the overall business case uncertainty. Therefore the new hybrid powerplant, with the wind farm and an onshore electrolyser has to be introduced. Similarly to the baseline case, the technical description and key uncertainties will be analyzed below in the present Section.

3.3.1. Technical description

The new hybrid powerplant has two distinct technical packages,the offshore farm and the electrolyser stack. The same wind farm as the baseline case is utilized for the hydrogen case, with a detailed technical overview in Section 3.2.1

The key addition compared to the baseline case is the electrolyser stack. It enters service three years later than the offshore wind farm. A maximum of three years, after the electricity-generating asset enters COD is what set by the European Union's regulations on green hydrogen [26]. Therefore, to realize the full benefit of cost reductions for electrolysis, while maintaining compliance with green H2 regulation, the full period of three years is utilized.

Regarding the stack technology, Proton Exchange Membranes are utilized, since they have the faster ramp up and down dynamics, despite PEM being more expensive in terms of CAPEX and OPEX compared to Alkaline Electrolysis (Section 2.1.2. Moreover, the stack degradation rate is modelled and the loss of output is included in the calculation. The degradation rate and stack lifetime are based on literature review of Section 2.1.2. All in all, the main technical inputs of the case integrating hydrogen into the wind farm, can be found in Table 3.9.

Parameter	Value	Unit
Offshore Wind Farm	See Table3.1	-
Electrolyser Placement	Onshore	-
Installed Power	400	MW
Stack Technology	Proton Exchange Membrane	-
Degradation Rate	2	% per annum
Stack Lifetime	70000	h
Electricity Consumption	0.06	MW per H2 kg

Table 3.9: Technical description of the hybrid powerplant case including the electrolyser.

Due to the uncertainty of the hydrogen off-takers and of the electrolyser costs, developers take a conservative approach to the installed capacity of the electrolyser. Hence, a 400 MW onshore electrolyser is proposed. This will constitute 25% of the 2 GW P_{rated} of the farm.

Based on the electricity consumption of 0.06 MW per kg of H2, the electrolyser outputs a maximum of 6667 kg of hydrogen per hour. Since the electrolyser is connected to an infinite gas-grid, all hydrogen can be absorbed without any constraints. Additionally, the electrolyser operates in two modes; either producing at full capacity or is inactive. Therefore, the operation of the electrolyser depends only on the HPA price and the electricity day-ahead prices. While the electricity price is below 66.6 €/MWh the electrolyser produces at full capacity and the hybrid plant exports both electricity and hydrogen.

3.3.2. Revenue uncertainties

The source of revenue uncertainty in the offshore wind farm is the unpredictability of the day-ahead markets. This uncertainty persists in the hybrid powerplant, since the day-ahead market price defines the offshore farm's revenues and as shown in Section 3.1.3, it is a key input for the dispatch decision. To quantify the revenue uncertainty of the hybrid powerplant a combination of the dispatch algorithm and Monte Carlo sampling is employed. The steps taken are similar to those described for the offshore farm (Section 3.2.3 are summarized below:

1. **Step 1:** The dispatch optimization is ran for the three electricity market scenarios, low, central and high and the hybrid plant revenues are calculated for each scenario.
2. **Step 2:** For each year, a triangular triangular distribution of the hybrid plants revenues is defined. The mode of the distribution corresponds to the revenues predicted for the central scenario. The minimum and maximum values of the distribution correspond to the low and high scenarios respectively.
3. **Step 3:** The revenue distributions for each year are input in the techno-economic model and 10000 samples are drawn based on Monte Carlo.

The novelty of the revenue uncertainty quantification methodology lies on the connection of the dispatch optimizer with the established techno-economic model, to assist in the evaluation of the hybrid project. The dispatch optimizer can calculate the revenues of the hybrid park, but is not capable of connecting revenues with costs for a complete assessment. Utilizing both models for a complete uncertainty assessment of a hybrid park is a first for Vattenfall.

3.3.3. Electrolyser uncertainties

As the hybrid powerplant consists of the offshore farm and the electrolyser, it combines the uncertainties of both. In addition to the uncertainties relevant to the offshore farm (discussed in Sections 3.2.3 to 3.2.6, CAPEX uncertainty is introduced by the electrolyser.

Based on expert interviews within the Vattenfall the uncertainty bands around the nominal CAPEX estimates are defined in Table 3.10. These bands are significant due to the immaturity of the technology- and reflect the difficulty to precisely estimate the investment requirements for H2 infrastructure. With a nominal CAPEX higher than 1M €/MW, the impact of the electrolyser on the cost uncertainty of the project is considerable.

electrolyser	Lower Limit	Upper Limit
CAPEX	-20%	30%

Table 3.10: electrolyser CAPEX & OPEX uncertainties

Summary

In summary, this Chapter introduced the modelling approach taken to quantify the impact of cost and revenues uncertainties, on the business case of an offshore wind farm and a hybrid powerplant. A techno-economic model is deployed to calculate the economic performance of the offshore wind farm, while a dispatch optimization is coupled with the latter model to derive the revenues of the hybrid park. To incorporate uncertainties, triangular distributions are defined that are randomly sampled with Monte Carlo. The main investment costs for the offshore farm are found in commodity prices, vessel, construction and project management costs. These uncertainties are also applicable to the hybrid powerplant, with the addition of the electrolyser cost uncertainty. Both the offshore farm and hybrid powerplant are exposed to revenue uncertainty arising from the unpredictability of the day-ahead prices.

4

Deterministic Case

During the pre-bid phase of the project point-estimates inputs are used in the techno-economic model to perform an initial feasibility assessment of the project. If the point-estimates indicate a promising project, further analysis is performed with the inclusion of uncertainties. Consequently, this Chapter aims at providing the deterministic results for the offshore wind and hybrid cases, to establish a baseline. First, Section 4.1 establishes a cost-and-revenue benchmark for the wind-only case. Then, Section 4.2 introduces the onshore electrolyser and presents the deterministic business case results of the hybrid farm. Finally, Section 4.3 compares the business cases of the two projects.

4.1. Offshore wind case

4.1.1. Costs

The largest CAPEX values for the wind farm are based on 2025 point-estimates, reflecting expected construction costs starting in 2028. They are summarized in Table 4.1. OPEX is also modelled in-detail, but the details are beyond the scope of the study.

Category	CAPEX [M €]	CAPEX [M € per MW]
WTG Supply	1995	0.95
WTG Installation	141	0.07
Foundation Manufacturing	473	0.23
Foundation Installation	318	0.15
Inter Array Cable Supply	267	0.13
Inter Array Cable Installation	100	0.05
Project Management	200	0.1
Construction Management	37	0.02

Table 4.1: Major cost items for the baseline case. The CAPEX values represent industry-wide standard estimates for the different cost items. No data presented here is based on supplier quotes.[1]]

The procurement of the turbine amounts for 46% of the project's CAPEX, followed by the manufacturing of the foundations at 11%. On the construction side, the main costs are the installation of the foundation and inter-array cabling, at 7 and 6% of total CAPEX respectively. The installation of the turbines captures 3% of the total CAPEX.

[1]For more information on data sources, see Section 1.7

Accounting for all CAPEX requirements of the proposed farm, the per MW CAPEX is calculated at 2.1 M € /MW. The investigated project value is on the lower end of the announced projects under permitting, based on the literature review of Section 2.1.1. The per MW cost deviation indicates how project site specific cost estimates are. Additionally, forecasting costs 5-8 years is associate with large uncertainties.

4.1.2. Revenues

The yearly revenues of the wind farm for the baseline case, based on the *central electricity scenario* of Section 3.2.3 are presented in Figure 4.1. Revenues tend to increase with the wind farms lifetime, due to the underlying assumption that electricity prices are inflation-indexed. Between COD and 2035, revenues drop since the day-ahead price drops. The revenue variation is attributed to mostly electricity-price variations, as the Annual Energy Production stands at roughly 9 TWh per annum, after including for all losses.

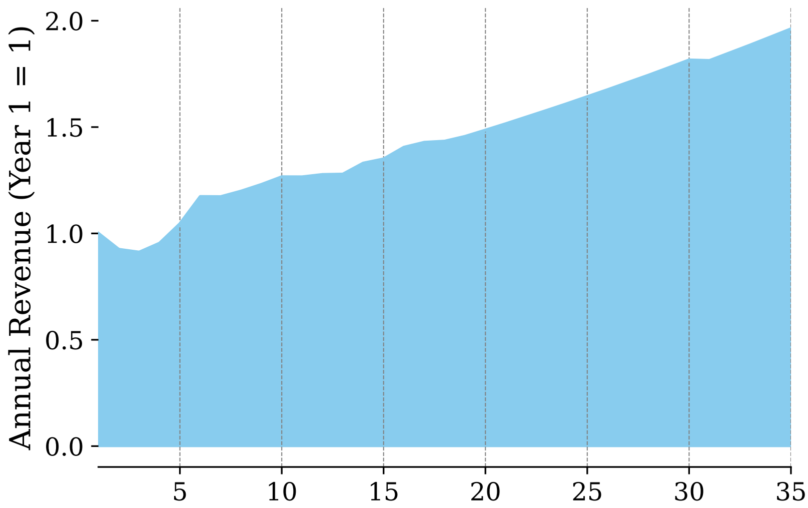

Figure 4.1: Wind farm annual revenues, indexed against inflation at a 2% annual rate. The revenues are based on simulations with day-ahead prices provided by Aurora Energy Research. The revenues have been normalized against the revenue of year 1.

4.1.3. Economic Performance

Given the costs and revenues of the baseline case, a deterministic evaluation of the business case is performed. All the KPIs are summarized in Table 4.2. *All values have been discounted with a WACC of 7%.*

KPI	Value	Unit
LEC	43.9	€ /MWh
IRR	8.0	%
NPV	543	M €

Table 4.2: Investment KPIs for the baseline case, with point-estimates for costs and revenues

The resulting project's LEC stands at 43.9 € /MWh and is 18% lower compared to Frauenhofer Institute's estimate [39]. This underscores the project-specific nature of the KPIs and the subjectivity of assumptions regarding cost de-escalation and learning effects.

Moving from LEC to the NPV and IRR, the project has an NPV € 645 M. Since the NPV is positive the project is profitable. However, this is a necessary but not sufficient condition to render it investable. In addition to the positive NPV, the IRR has to be above the DHR. The IRR stands at 8.0%, equal to the Direct Hurdle Rate of 8%, defined in Section 3.2.2.

4.2. H2-integration case

4.2.1. Costs

The costs of the hybrid powerplant are the same as the offshore-wind case, presented in Table 4.1, excluding the investment costs and operations & maintenance costs of the electrolyser. Based on internal estimates, the addition of a 400 MW Proton Exchange Membrane electrolyser will increase the CAPEX by 17%, compared to the offshore wind CAPEX. This number includes all Balance of Plants components (compressors and power electronics) necessary to operate the stacks. The O&M of the electrolysis plant is considered constant per annum at 2% of the plant's CAPEX. The CAPEX and O&M of the entire hybrid plant are summarized in Table 4.3.

Category	CAPEX [M €]
CAPEX	+17% of wind farm's CAPEX
OPEX	2% of electrolyser's CAPEX per annum

Table 4.3: Major cost items for the electrolyser. TThe CAPEX values represent industry-wide standard estimates for the different cost items. No data presented here is based on supplier quotes.[2]]

In addition to investment and operation costs, the electrolyser has a variable operating costs, related to the procurement of electricity from the day-ahead market. Under specific circumstances of low-wind the electrolyser procures its electricity from the day-ahead market. This happens less than 25% of the time, as 75-80% of the electrolyser needs are directly covered by the wind farm.

4.2.2. Revenues

The hybrid powerplant has two revenue sources; sales of electricity to the day-ahead market and sale of H2 to off-takers at the steady price of 4 € /kg. Before the electrolyser comes online, the revenues are identical to the baseline case. Once the electrolyser is operational in 2035, a rapid increase in revenues is observed due to the sales of H2. The breakdown between revenues from electricity and H2 sales can be read on the right axis of Figure 4.2.

In the first 10 years of operation, the relative contribution of H2 to the hybrid park's income is constantly decreasing, from 40 to 24%. This is attributed to the expected increase of prices in that period. As described on the dispatch decision, the higher the electricity price, the less economical H2 production is, given a constant HPA price. Overall, through the entire farm's lifetime the capacity factor of the electrolyser is 72%, this translate that 72% of the time, the electricity price is below the break-even price of 66.6 €/MWh (Appendix B.

4.2.3. Economic performance

The KPIs for the hybrid powerplant are summarized in Table 4.4. The LEC stands at 43.9 € /MWh same as the wind-only case. According to LEC's definition in Section 2.1.4 only costs relevant to the wind farm are included in its calculation. Moreover, including the electrolyser does not significantly increase the AEP, due to reduced curtailment. The IRR is calculated 8.1% with a positive Net Present

[2]For more information on data sources, see Section 1.7

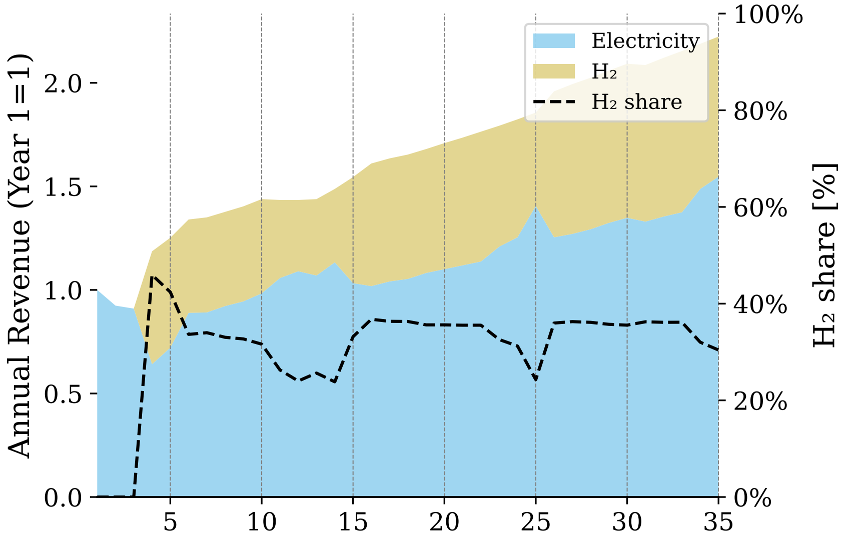

Figure 4.2: Annual Revenues breakdown of the hybrid powerplant on the left axis. Right axis presents the relative share of H2 sales to the total hybrid park revenues. Revenues are indexed against inflation at 2% per annum rate. The revenues are normalized against year 1 of the plant's operation. The revenues are based on simulation with day-ahead prices provided by Aurora Energy Research.

Value of 622 M EUR. Since the IRR is above the defined Hurdle Rate of 8%, the Hydrogen Project is investable, without considering the effect of uncertainties.

KPI	Value	Unit
LEC	43.9	€ /MWh
LCOH	3.5	€ /kg
IRR	8.1	%
NPV	622	M €

Table 4.4: Investment KPIs for the H2 integration, with point-estimates for costs and revenues. The KPIs have been derived from the techno-economic model, using industry-standard inputs for the offshore and electrolyser costs, and Aurora Energy Research day-ahead data.

The Levelized Cost of Hydrogen has been calculated based on Equation 2.3, with all the H2 costs attributed to LCOH and not LEC. Including the CAPEX, OPEX and procurement of electricity to run the electrolyser the LCOH stands at 3.5 € /kg, well within the limits for similar projects presented in literature 2.1.4. The LCOH is below the HPA price, indicating the positive effect of H2 inclusion in the project's economic performance.

4.3. Comparison between offshore wind and H2-integration

Introducing a 400 MW electrolyser impacts both the costs and revenues of the now hybrid powerplant. Specifically, the project's CAPEX is increased by 17%, while the OPEX by 12.5%. On the revenues side, the revenues increase by 12.5% through the sales of H2. The CAPEX, OPEX and revenues of the two projects are summarized in Figure 4.3.

Is this jump on revenues by 12.6% compared to the wind-only case enough to justify the CAPEX and OPEX increase due to the addition of the electrolyser? Considering a comparison of the KPIs in Table 4.5 indicates the investments perform similarly, with the electrolyser addition only increasing

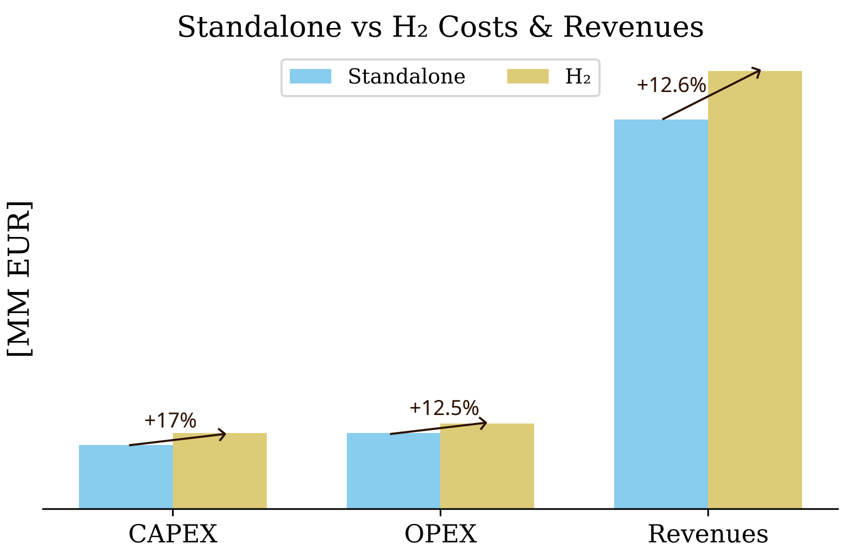

Figure 4.3: CAPEX, OPEX & Revenues comparison between the offshore-wind-only case and the H2-integration case. Numbers are expressed in real terms.

the IRR by 0.1 percentage points. The increase in NPV is on the order of 79 M €.

KPI	Offshore wind	Hybrid	Δ	Unit
LEC	43.9	43.9	0	€ /MWh
IRR	8.0	8.1	0.1	p.p
NPV	543	622	79	M €

Table 4.5: Investment KPIs comparison between the offshore wind and hybrid projects. Δ is with respect to the offshore wind case.

Overall, the marked increase increase in revenues is not associated with a significant increase in returns as quantified through the Internal Rate of Return. The increases in CAPEX and OPEX are not outweighed by the additional revenues of due to the timing of the cashflows and the discounting effect. The additional revenues are spread over the farms lifetime and thus are heavily discounted, compared to the additional CAPEX of the electrolyser. Therefore, the increase in revenues is consumed by the increase in CAPEX, leading to a project with similar performance.

Comparing the two projects in terms of investability, preference over the offshore wind farm shall be given. Despite the higher revenues of the hybrid plant, the investment returns as quantified through the Internal Rate of Return (IRR) are similar. Given the very high investment costs in the order of € 5 BN for the offshore wind farm, it is highly unlikely to undertake an investment that will increase the IRR by 0.1 percentage points, but will increase the CAPEX by 17%. Already, capital investments in the order of € 5 BN pose limitations to the balance-sheets of large corporations.

5 Uncertainty Analysis

The deterministic assessment of the economic performance of the offshore farm and the hybrid powerplant of Section 4.3 is in favor of the offshore wind farm, in terms of investment returns. This chapter addresses the goal of the thesis and introduces uncertainties in the evaluation of the two projects. Specifically, Sections 5.1 and 5.2 present the business-case outcomes under uncertainty for the wind-only and hydrogen-integrated projects. Finally, Section 5.3 directly compares the economic performance metrics under uncertainty. Based on the results of the comparative uncertainty analysis, conclusions regarding the uncertainty effect of hydrogen synergies with offshore wind will be drawn.

5.1. Offshore wind case under uncertainty

The initial, deterministic evaluation of the offshore case is positive, as indicated in Section 4.1. The offshore wind farm just meets the Direct Hurdle Rate of 8%. In a deeper analysis, the impact of uncertainties is considered to determine how robust the business case is and with what confidence the outcome of the investment will meet the hurdle rate.

5.1.1. Impact of cost and revenue uncertainties

On the cost side, four uncertainty categories are included: a) commodity prices b)vessel day-rates c)Adverse Weather Downtime d)construction & project management costs. [1]. These uncertainty sources will in turn affect the investment costs of the offshore farm. On the revenue side, the uncertainty around the day-ahead price of the *central scenario* has been considered to reflect the uncertainty on the forecasts of the day-ahead price, as described in Section 3.2.3.

After simulating 10000 outcomes of the offshore farm through the Monte Carlo approach and the techno-economic model, the entire range of outcomes is effectively sampled. Additionally, the 10000 samples lead to a converged solution, that assures statistical significance of the results. The convergence plots can be found in Appendix C. The 10000 different realizations of the project achieve through Monte Carlo provide significant insights into the impact of the four uncertainties sources on the major investment costs for the wind farm.

To understand which costs are more impacted by the presence of uncertainties, the Interquartile Range (IQR) between the P50 and P10, P90 [2] values have to be visualized. These ranges, in particular the P90-P50, helps quantify the extent of the CAPEX uncertainty for each component. Specifically, the

[1] For more details on the uncertainties derivation, see Sections 3.2.4 to 3.2.6

[2] P10: 10% of outcomes lie below, P50: 50% of outcomes lie below and is equal to the median, P90: 90% of outcomes lie below

P90-P50 spread is indicative of the potential cost overruns, as the P50 is the median CAPEX estimate and P90 is a worst-case value. Consequently, this spread can help inform the contingency budget of the project.

Figure 5.1 presents a tornado chart, where the P90-P50 and P50-P10 spreads are normalized over the median and the text indicates the median CAPEX value. Evidently, the largest P90-P50 spread, in the order of 7.5% is associated with the installation of the WTGs. Installation of foundations and the Inter Array Cabling (IAC) also come with significant CAPEX uncertainty, with an upside potential of 5%. For the top three CAPEX packages (WTG, foundation and IAC installation) the common source of uncertainty is the vessels. The vessel cost is a key driver for installation procedures and come with large amounts of uncertainty in the fuel consumption, fuel commodity price and the day rates. Additional uncertainty in the vessel costs and thus installation costs, is introduced by the Adverse Weather Downtime.

In terms of commodities, steel price uncertainty has the largest impact, The WTG procurement and manufacturing of the offshore substation's foundation are much less sensitive to steel uncertainty, with less than 1% uncertainty. Aluminum and Copper uncertainty has a negligible effect on the CAPEX of the offshore export and IAC cables. All in all, the largest CAPEX uncertainty is in terms of normalized P90-P50 spread is attributed to the installation procedures.

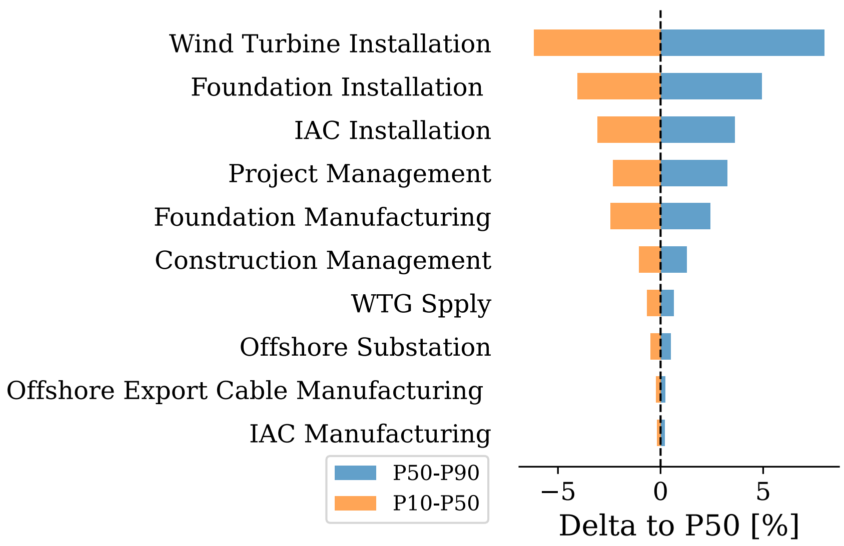

Figure 5.1: Uncertainty bands of major CAPEX packages. The bars represent the Interquartile Ranges P10-P50 and P50-P90.

Figure 5.1 introduced the expected CAPEX uncertainty for the major investment costs of the wind farm. The uncertainty was expressed as a percentage deviation compared to the median value. To move from this package-specific view, to identifying the **key uncertainty drivers**, the correlation between the variation in the costs and revenues and the project's IRR has to be quantified, through the Spearman correlation, introduced in Section 3.1.6. The results are presented in Figure 5.2.

The uncertainty in revenue, as quantified by the sum of all the discounted revenues (Present Value) has the largest impact on the project's IRR variation ($r_s = 0.88$), twice the impact of the next driver, foundation installation ($r_s = -0.26$). Installing the Foundations is the most expensive installation process and has significant uncertainty due to vessel operations, rendering it the key cost-driver. The uncertainties on installation of the WTG and IAC and the foundation manufacturing have similar ranking from 3rd to 5th, followed by the uncertainty on the WTG supply price. Finally, Project Management and the cost associated with the foundation of the Offshore Substation have the least impact, with a Spearman-rank coefficient of less than 0.1.

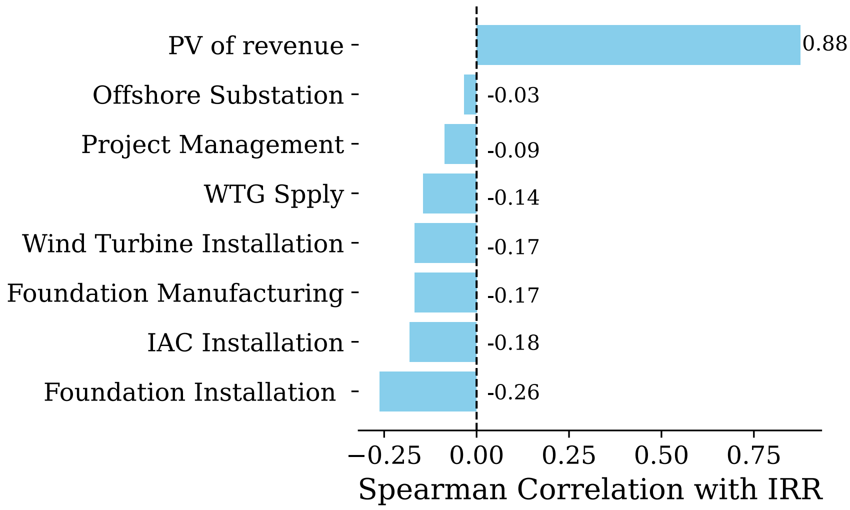

Figure 5.2: Spearman correlation coefficient r_s[3] between the CAPEX drivers and the project's IRR, for the wind-only case. Only CAPEX packages with a p-value lower than 0.05 are included for significance.

Comparing the uncertainty drivers (Figure 5.2) with the packages most affected by uncertainty (Figure 5.1), there is a discrepancy. The wind turbine installation cost is the most impacted by uncertainty, but is only the 4th uncertainty driver. This difference arises because for a package to be an uncertainty driver, both the uncertainty and the absolute cost are relevant. For example, the WTG installation has a high uncertainty but the cost is lower compared to the other installation procedures, therefore it is ranked lower as a driver.

5.1.2. Economic performance

The analysis of the contribution of cost and revenues uncertainties, indicated the revenue is the main driver of business case uncertainty. However, the combined impact of including costs and revenue uncertainty, on the Net Present Value and Internal Rate of Return has to be evaluated. Through utilizing the 10000 Monte Carlo simulations, the Probability Density Functions and statistical metrics of NPV and IRR can be estimated.

Figure 5.3 presents the NPV and IRR Probability Density Functions. Both NPV and IRR distributions are almost perfectly symmetrical with their skewness calculated at -0.023. This symmetry suggests that the uncertainties affecting the economic viability of the offshore-wind-only scenario are balanced, indicating that there is no significant bias toward overly optimistic or pessimistic outcomes. The symmetry arises from the uncertainty definitions, which are always triangular and not skewed. Additionally, the symmetry in outcomes suggest **the effect of cost uncertainties is balanced by the volatility in the energy market**.

The Interquartile Ranges and P10, P50 and P90 values are summarized in Table 5.1. The spread between the median (P50) NPV and the most optimistic outcome described by the top 10% of outcomes (P90) is 60 M €, equal to the spread between the median and most pessimistic outcomes described by P10. Similarly, the IRR P10-P50 and P50-P90 spread is 0.1 p.p. **The probability the project does not meet the DHR of 8% is 54%.**

As evident from Table 5.1 the revenues have the largest uncertainty, with a downside potential quantified through the P50-P10 spread, in the order of € 70 M, more than 2.5 times the upside potential of the CAPEX. € 70 M presents a 1.3% deviation compared to the median revenue estimate. Again,

[3] For more details see Section 3.1.6

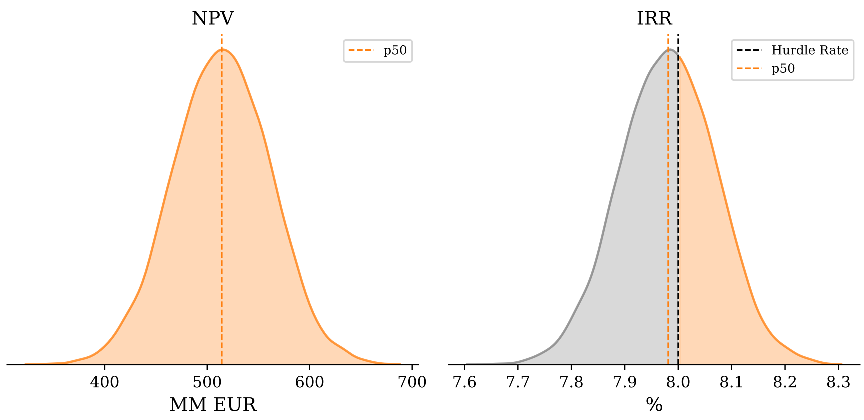

Figure 5.3: Probability Density Functions for NPV and IRR for the offshore-wind case. The grey area on the IRR plot indicates the outcomes below the DHR of 8%.

this value appears limited compared to the market volatility, in the order of 20%. This figure can be explained by two observations related to the methodology of Section 2.2.1:

- **The uncertainty quantification methodology applied to revenues:** Since the revenue uncertainty is quantified by sampling from a triangular distribution of revenue outcomes each year. Going back to Figure 3.5 the volatility is sampled for each year and despite the randomness, all the different revenue realizations will tend to converge to the median. Additionally, there is no inter-year correlation, because Monte Carlo samples each year independently, leading to a year with high revenues followed by a year with low.
- **The metric used to compare revenues:** The Present Value is used for the revenues, to bring it to comparable terms with CAPEX. Consequently, the discounting effects will affect the P50-P10 spread, since the first years of operational revenues will have a higher impact on the PV rather than future years. Therefore, the present value of revenues will tend to be biased towards the revenue uncertainty of the first years.

KPI	P10	P50	P90	IQR P10 - P50	IQR P50-P90
NPV [M €]	454	514	574	60	60
IRR [%]	7.9	8.0	8.1	0.1	0.1
CAPEX [M €]	4373	4401	4429	28	29
PV Revenues [M €]	5657	5728	5797	70	69

Table 5.1: P10, P50, P90 values along with the respective P10-P50 and P50-P90 Interquartile Ranges, for the offshore wind case NPV and IRR. The numbers are based on 10,000 Monte Carlo runs and the output of the techno-economic model. The inputs are based on industry standard projections for costs.

Despite the large uncertainties in costs and day-ahead price volatility, the uncertainty in the project's profitability remains modest. This is attributed to the nature of Monte Carlo simulations, where all input uncertainties are sampled jointly. Therefore, a high-cost turbine scenario may coincide with favorable day-ahead prices. In addition, the uncertainties are described by triangular distributions, leading to narrow outcomes.

However narrow, with 80% of outcomes lying within 0.2 p.p of the median IRR, the IRR spread is crucial. During the development phase, several months and extensive negotiations can be underway to improve the IRR by 0.1 p.p. Consequently, the inclusion of uncertainty can show that marginal

IRR improvements fall within the model's inherent variability, emphasizing the need to consider full distributional outcomes. Additionally, the inclusion uncertainty, shifts the median IRR value to 7.9%, 0.1 p.p lower than the deterministic IRR of 8.0%, the equivalent values to compare.

To sum up, including uncertainties changes the project's economic outcome, with day-ahead market volatility being the key uncertainty driver, followed by the foundation installation. Moreover, considering uncertainties changes the project economic evaluation compared to the deterministic case. In the deterministic case the project was investable with an IRR of 8%, but now including uncertainties the project has a quantified risk profile, where the probability of not meeting the 8% DHR is 54%.

5.2. H2-integration case under uncertainty

In the previous Section 5.1, it was shown that inclusion of uncertainties can change the evaluation of project from positive, to one with more than 50% chance to not meet the Hurdle Rate. The deterministic evaluation of H2 integration led to a project, with an IRR of 8.1%. The same analysis as Section 5.1 is undertaken here. This will help conclude about the financial feasibility of the H2-integration project under the presence of uncertainties.

5.2.1. Impact of cost and revenue uncertainties

The project with offshore-wind and H2 synergies, inherits the same CAPEX uncertainties from the standalone case, discussed above. The wind farm has to be constructed, before connecting it with the electrolyser. *The major source of uncertainty which is added is the electrolyser's CAPEX.*

The CAPEX of the electrolyser has the most uncertainty in the order of 15% compared to the median estimate. In line with the uncertainty definition of Section 3.3.3, CAPEX is skewed more towards the P90, underscoring the pessimistic assumptions for the electrolyser's cost development. The remaining packages have the same uncertainty as the offshore-wind-only case of Figure 5.1.

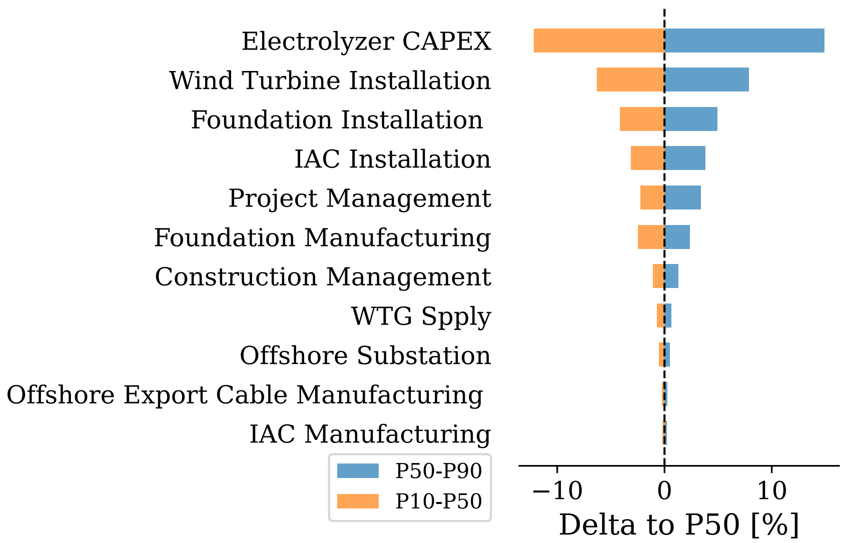

Figure 5.4: Uncertainty bands of major CAPEX packages. The bars represent the Interquartile Ranges P10-P50 and P50-P90.

The electrolyser requires significant investment to be build. Specifically, it is the second largest expense of the hybrid powerplant after the procurement of the WTGs. The large uncertainty associated with its investment along with the high absolute costs, propel it to be the key uncertainty driver for the hybrid powerplant, as reflected in Figure 5.5. The electrolyser has the highest Spearman rank of $r_s = 0.73$, rendering the main uncertainty driver. Revenues rank second with $r_s = 0.56$. Compared to the remaining CAPEX uncertainty sources, electrolyser has at least a three-fold impact.

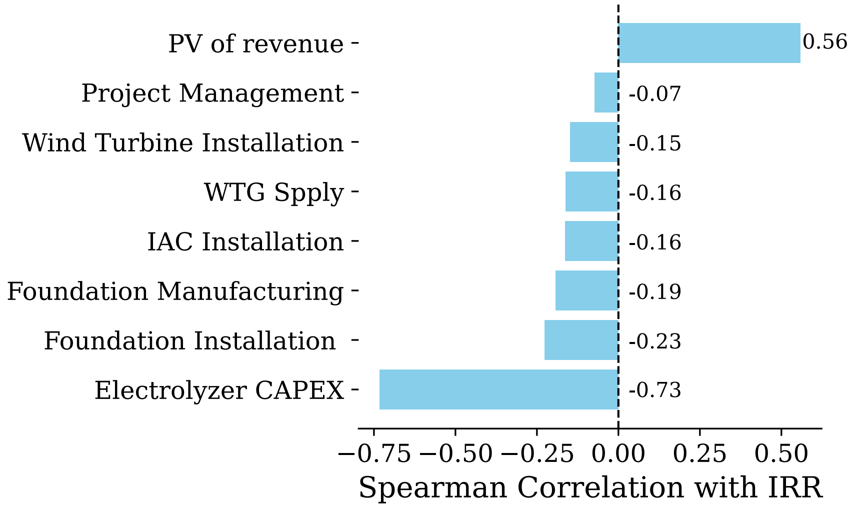

Figure 5.5: Spearman correlation coefficient r_s[4] between the CAPEX drivers and the project's IRR, for the H2 case. Only CAPEX packages with a p-value lower than 0.05 are included for significance.

5.2.2. Economic performance

It has been made clear that introducing the electrolyser adds significant amount of costs and uncertainty. How does that affect the overall project profitability, considering that the H2-integration has a positive effect on increasing revenues?

Figure 5.6 presents the Probability Density Functions calculated for the H2 integration case, with both cost and revenue uncertainties included. Both NPV and IRR distributions are symmetrical, giving no weight on positive or negative outcomes. Moreover, the median IRR 8.0% is equal to the DHR. Therefore, the median project meets the hurdle rate and is investable. Compared to the H2-integration deterministic case (Section 4.2, this is a 0.1 p.p drop in the IRR, signifying the necessity of an uncertainty quantification analysis.

The Interquartile Ranges and P10, P50 and P90 values are summarized in Table 5.2. The spread between the median (P50) NPV and the most optimistic outcome described by the top 10% of outcomes (P10) is 74 M €, equal to the spread between the median and most pessimistic outcomes described by P90. Similarly, the IRR P10-P50 and P50-P90 spread is 0.1 p.p. The probability of the project not meeting the DHR of 8% is 45%.

Despite the large uncertainties in costs and day-ahead price volatility, in the order of 20%, the uncertainty in the project's profitability remains modest. The IRR spread is narrow, with a spread of 0.2% between the most pessimistic ($P10 = 8.1\%$) and most optimistic ($P90 = 7.9\%$) outcomes. This is a consequence of the additive effect of the electrolyser on the hybrid powerplant's revenues. The electrolyser lifts the costs and CAPEX uncertainty significantly, but in parallel increases the hybrid powerplant's revenues, keeping the project competitive overall.

To conclude, the integration of H2 in the wind farm adds a major source of uncertainty, that of the electrolyser's CAPEX, dominating over every other cost uncertainty by a factor of three. The electrolyser integration reduces the importance of revenues uncertainty, to a secondary source. Based on the Probability Density functions, the Internal Rate of Return has a 55% probability to be above the

[4]For more details see Section 3.1.6

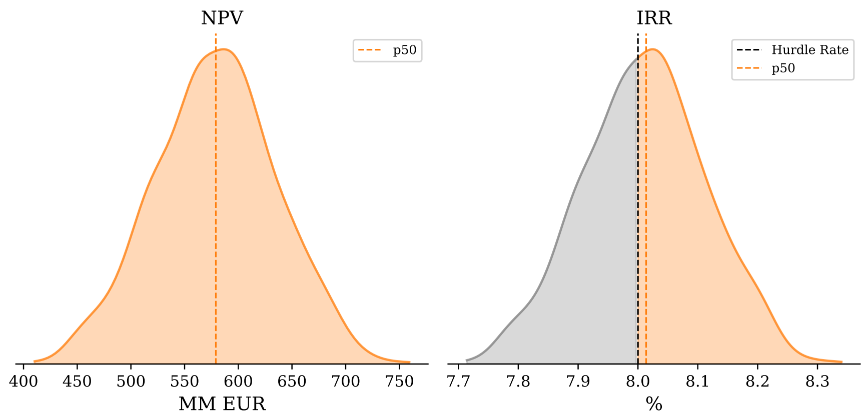

Figure 5.6: Probability Density Functions for NPV and IRR for the H2 case. The grey area on the IRR plot indicates the outcomes below the DHR of 8%.

KPI	P10	P50	P90	IQR P10 - P50	IQR P50-P90
NPV [M €]	506	579	653	73	74
IRR [%]	7.9	8.0	8.1	0.1	0.1
CAPEX [M €]	5110	5212	5334	102	123
PV Revenues [M €]	6380	6432	6483	52	51

Table 5.2: P10, P50, P90 values along with the respective P10-P50 and P50-P90 Interquartile Ranges, for the H2 case NPV and IRR. The numbers are based on 10,000 Monte Carlo runs and the output of the techno-economic model. The inputs are based on industry standard projections for costs.

hurdle rate, deeming the median project investable.

5.3. Comparative uncertainty assessment

A direct comparison of the uncertainty associated with the offshore wind farm against the H2 integration is necessary, for an informed decision between the two projects. Similar to the preceding Chapter, CAPEX uncertainty will be compared across the projects in Section 5.3.1, revenue uncertainty in Section 5.3.2 and finally the NPV and IRR comparison in Section 5.3.3.

5.3.1. CAPEX uncertainty comparison

Table 5.3 compares the two projects in terms of the P90-P50 spread. This value is indicative of the additive effect the electrolyser has on the project's CAPEX. This spread is a key uncertainty metric within Vattenfall, as it informs how much budget shall be set aside during the bid phase, in order to account for potential cost overruns. For example, if the electorlyser CAPEX is budgeted based on the median value but during FID (financial close) the P90 value comes up as the agreed price, the construction will fall out of budget, by P90-P50.

Due to the marked difference in the project investment amounts, both the absolute P90-P50 and normalized $\frac{P90-P50}{P50}$ will be deployed to compare them. For the offshore wind case, the P50–P90 spread is 29 M € . In contrast, the H2 integration project exhibits a P50–P90 spread of 123 M € , a marked € 94 M increase in the contingency budget. Since all other cost uncertainties remain equal, the additional € 94 M in CAPEX uncertainty is fully contributed by the electrolyser. Normalizing by the median project CAPEX, the inclusion of the electrolyser brings a significant increase of 1.8 p.p.

The increased contingency budget requirement to cover for the electrolyser CAPEX uncertainty has a direct implication on Vattenfall's bidding strategy. Assume a tendering process where Vattenfall bids in a competitive tender project. In that case, the additional € 94 M of cost contingencies will have to be included in the bidding price, eroding competitiveness. Another bid strategy can be taken, to accept higher risks by budgeting based on the P50-P80. This leads to lower contingency budgets, but a higher risk. In principle, this risk could be accepted by Vattenfall, since the company finances the projects on-balance sheet [5]. Hence, there are no external lenders imposing contingency budget targets and they can be decided internally based on the uncertainty-return profile.

CAPEX	Offshore Wind	H2 Integration	Δ H2 - Offshore Wind
P50-P90	29	123	94
$\frac{P90-P50}{P50}$	0.6%	2.4%	1.8 p.p

Table 5.3: P50, P10 and P90 CAPEX values comparison between the Offshore Wind and H2 case. CAPEX is expressed in nominal €terms.

5.3.2. Revenue uncertainty comparison

It is clear that integrating the electrolyser increases the project's CAPEX uncertainty, as quantified by the contingencies interval. Whether the additional CAPEX uncertainty can be accepted, depends on the effect of H2 integration on the project revenues. To compare the effect on the revenues, the P10, P50-P10 and normalized P50-P10 metrics are utilized. Contrary to costs, where the potential overruns are necessary for budgeting, the potential under-performance of the revenues is relevant for revenues.

Revenue PV [M €]	Offshore Wind	H2 Integration	Δ H2-Offshore Wind
P10	5657	6380	723
P50	5728	6432	704
P50-P10	70	52	-18
$\frac{P50-P10}{P50}$	1.2%	0.8%	-0.4 p.p

Table 5.4: P50, P10 and P90 of Revenues Present Value comparison between the Offshore Wind and H2 case. Revenue PV is expressed in discounted €terms.

Table 5.4 compares the Present Value of all revenues for the Offshore Wind and H2 integration cases. In terms of worst-case (P10) revenues the electrolyser lifts them by € 723 M and of median (P50) by € 704 M. The increase in revenues is directly attributed to the sales of H2. By lifting the P10 revenues more compared to the P50, the electrolyser mitigates the P50-P10 uncertainty by € 18 M or 0.4 p.p, compared to the offshore wind case. The uncertainty mitigation of € 18 M compared to the offshore wind case is not significant. This can be attributed to the following:

1. **Dispatch of the electrolyser:** The electrolyser is dispatched based on the day-ahead price P_{DA} and a binary decision. As long the P_{DA} is below the break-even price [6], the electrolyser produces at full-capacity. Otherwise, the electrolyser is offline. Since the prices are simulated from a triangular distribution that is heavily concentrated around the central price, few extreme scenarios are sampled that lead the electrolyser to switch operation mode. To achieve a significant de-risking effect, the revenue P10 values shall be closer to the median, thus the P_{DA} distributions should be skewed towards the low scenarios, where the electrolyser is more utilized.
2. **Electricity market:** The de-risking effect of the electrolyser is also related to the expected market uncertainty, which has been quantified as the difference between the central and low

[5] For more information on on-balance sheet financing, see Section 2.1.5
[6] For more information on the derivation of the break-even price, see Appendix B

electricity scenarios. The market considered is Sweden, which is a cheap and relatively robust in terms of volatility. Hydropower occupies a large share of Sweden's energy mix and this tends to decrease prices and smooth the volatility. The low prices assist in H2 production, because there are plenty hours where P_{DA} is below the break-even price. The low volatility does not favor the de-risking of revenues by hydrogen, because the market lacks significant price-swings that will change the operational mode of the electrolyser and thus offer uncertainty reduction.

3. **Hydrogen Purchase Agreement price:** Finally, the reduction in revenue uncertainty is linked to the assumed HPA price of 4 €/kg. The HPA price is one of the key inputs that determines the break-even price. The higher the HPA price, the higher the break-even price. If the day-ahead prices remain equal, the electrolyser will have an increased capacity factor. This will increase the revenues of the hybrid powerplant, but will further decrease the de-risking effect of the electrolyser on the revenues, since the spread between the break-even and day-ahead prices will be larger. Given the dispatch of the electrolyser, the gains come from the additional revenues rather than the de-risking effect. Thus it would not be meaningful to aim for a lower HPA price, to increase the uncertainty-mitigation effect but lowering the absolute revenues.

To conclude, the addition of the electrolyser lifts the hybrid powerplant revenues significantly compared to the wind farm. However, limited uncertainty reduction effect can be expected. The electrolyser's dispatch decision, in combination with the Hydrogen Purchase Agreement price and the fundamentals of the Swedish day-ahead market are the main points that explain the € 18 M decrease in the revenue downside of the hybrid compared to offshore-wind.

5.3.3. Economic performance comparison

Integrating the electrolyser with the 2 GW offshore farm in a hybrid configuration increases the CAPEX uncertainty as quantified through the P50-P90 interval. Simultaneously, the electrolyser decreases the revenue downside potential, as quantified through the P50-P10 interval. The aggregated impact of costs and revenues uncertainties is quantified through a graphical comparison of the IRR and NPV distributions of Figure 5.7.

Consistent with the deterministic comparison of Section 4.3 the hybrid project has a higher IRR. In Figure 5.7 the median (P50) IRR is visualized through the vertical line and the expected median IRR is higher for the hybrid case. This means that even after considering uncertainties, the results of the deterministic comparison still hold, with the hybrid project showing an incremental increase in IRR. Despite the higher median IRR, the synergy between offshore wind and hydrogen **is overall riskier**, as the PDF corresponding to the H2-case is wider. **The standalone case exhibits a larger peak around the median (P50) indicating the outcomes are concentrated around the median outcome.**

The fact that the H2 project comes across as more uncertain is connected with the results presented in Sections 5.3.1 and 5.3.2. The increase in CAPEX uncertainty (€ 94 M) outweighs the decrease in revenue uncertainty (€ 17 M). Hence, the hybrid project is riskier. The increase in uncertainty is difficult to visualize through the IRR PDF, because it is a relative metric that normalizes the project returns with costs. The NPV can paint a more clear picture of the uncertainty comparison, since it utilizes absolute values. To help understand the PDF of Figure 5.7, Table 5.5 is introduced, with the uncertainty bands normalized over the median, for both cases. Since both projects have different median NPVs, normalizing the uncertainty bands allows for direct comparisons. The increased uncertainty of the hybrid is reflected by the delta between the normalized uncertainty bands, with increases of around 1% for both the left and right tails of the NPV distribution. Overall, the hybrid project has a wider NPV distribution by 2 p.p.

NPV	Offshore Wind	H2 Integration	Δ H2-Offshore Wind
$\frac{P50-P10}{P50}$	11.7%	12.6%	0.9 p.p
$\frac{P90-P50}{P50}$	11.7%	12.8%	1.1 p.p
$\frac{P90-P10}{P50}$	23.5%	25.5%	2.0 p.p

Table 5.5: P10, P50 and P90 of Net Present Value comparison between the Offshore Wind and H2 case

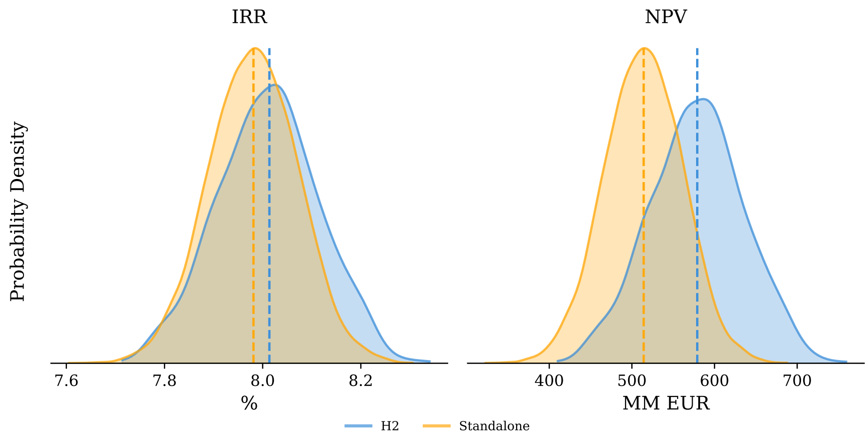

Figure 5.7: IRR and NPV Probability Distribution Functions comparison for the H2 integration case and the offshore-wind-only (standalone) case. The vertical lines indicate the P50 values.

It can be concluded that the hybrid powerplant and the offshore wind farm have similar economic performance. Both deliver an IRR close to the hurdle rate, with the hybrid project having a higher NPV, as both costs and revenues are higher inflating the numbers. In terms of business-case uncertainty, the inclusion of the electrolyser slightly increases the IRR and NPV uncertainty, due to increase in CAPEX uncertainty and limited decrease in revenue uncertainty.

Based on the integrated view which incorporates cost and revenue uncertainties, the offshore wind farm is more attractive from an investor perspective. It is less risky in terms of overall business-case uncertainty and it is shown that to realize the hybrid project, significant CAPEX uncertainty will have to be undertaken in the form of increased contingency budget, with a limited reduction in revenue uncertainty. This increased uncertainty is not rewarded neither with a less risky project, nor with a project with higher financial returns.

6 Sensitivity Analysis

Three key factors of the analysis were assumed, namely the cost-of-capital, Hydrogen Purchase Agreement price and the CAPEX of the electrolyser. These factors were elected to best represent the project specifications and the current market assumptions. Due to their high influence and the dynamic nature of the macroeconomic environment, a sensitivity analysis is performed to identify how these key external parameters affect the uncertainty comparison between the offshore farm and the hybrid powerplant. Section 6.1 is dedicated to the sensitivity of the two project's in the cost of capital, with Section 6.2 repeating the analysis for three different Hydrogen Purchase Agreement prices. Finally, Section 6.3 considers the impact of varying the electrolyser's CAPEX.

6.1. Cost of capital

The cost of capital, as quantified through the Weighted Averaged Cost of Capital (WACC, Section 3.2.2) is dynamic, reflecting changes in internal and macroeconomic environment. The offshore wind farm and the hybrid powerplant are heavily capital intensive, exceeding € 5 BN in CAPEX. Capital intensive projects are sensitive in WACC, as changes in WACC affect the Net Present Value of the investment. Hence, variations in WACC not only influence the performance of each project standalone, but also the relative ranking. To understand the sensitivity of the offshore wind farm and the hybrid projects to variations in WACC, a sensitivity analysis is performed. In the sensitivity analysis, all the uncertainties are incorporated.

A variation of ±1 percentage points around the nominal WACC assumption of 7% is employed to represent changing macroeconomic conditions. A lower WACC represents an improved macroeconomic environment, with lower interest-rates and risk premiums requested by lenders. On the contrary, a higher WACC indicates a worsening macroeconomic situation, reflecting higher interest rates or significant uncertainty, cultivating in high risk premiums. The results of the sensitivity analysis are depicted in Figure 6.1, where the nominal case assumption (WACC=7%) has been set as a baseline, and the results are presented with respect to that.

Both projects exhibit similar sensitivity to WACC. If WACC increases, significant improvements in the Net Present Value of the investment in the order of € 700 M are expected. The difference between the two projects is similar to the analysis presented in Section 5.3. However, if WACC drops, the profitability of both projects will dramatically improve and in that environment, the higher uncertainty of the hybrid project could be accepted. In case the profitability margin of both projects is higher, increased uncertainty-appetite can be accepted.

In case that macroeconomic conditions worsen and WACC is increased, the NPV of both projects

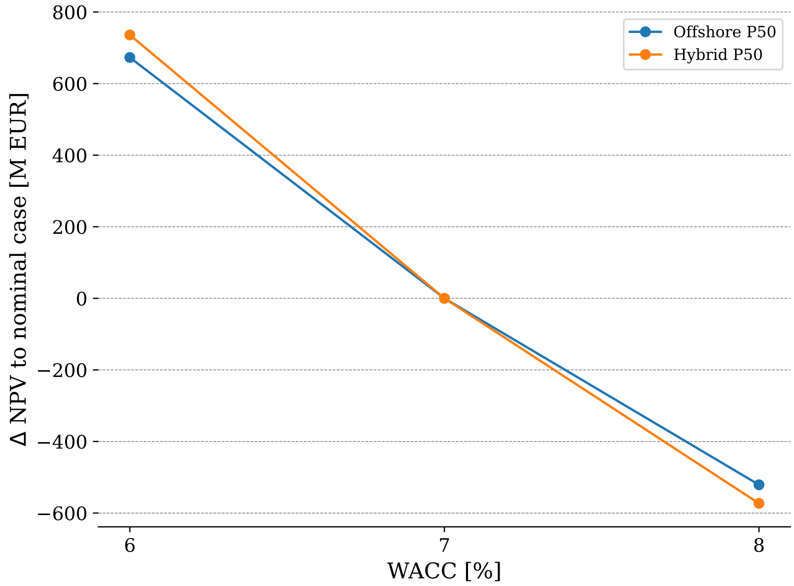

Figure 6.1: Sensitivity of the median (P50) NPV to variations in cost of capital (WACC). The sensitivity is presented with respect to the nominal WACC assumption of 7%. The results include all uncertainties.

plummets by almost €600 M, compared to the NPV of the nominal case (WACC=7%). In these worsening macroeconomic conditions, both projects have negative NPV and thus are non-economical. This is another important conclusion, indicating that if the cost of capital increases above a certain level, no projects can be build and the comparison between a hybrid and an offshore wind farm is not meaningful.

6.2. HPA price

An HPA price of 4 €/kg has been considered, based on published HPA agreements. The HPA price affects the revenue calculation of the hybrid powerplant. An increased HPA price, increases the revenue from H2 sales and simultaneously lowers the electricity price floor, as demonstrated in Appendix B. Overall, the higher the HPA price, the more attractive the H2 project will appear. As 4 €/kg is considered a price on the lower end of the spectrum, the sensitivity analysis covers 4.5 €/kg and 5 €/kg. The cost and revenue uncertainties remain the same across all three HPA cases.

The results of this analysis are presented in Figure 6.2. Specifically, the project's NPV and the median (P50) revenues are compared against the offshore wind farm, with the NPV on the left and revenue on the right axis. Increasing the HPA price has a significant effect in the project's NPV and total revenues. A 0.5 €/kg increase compared to the nominal HPA, yields a €180 M and €230 M increase in NPV and total revenues respectively. In a best-case scenario, with high demand for hydrogen and an HPA price of 5 €/kg, an additional €221 M and €278 M can be gained.

It has been calculated that the revenue uncertainty does not significantly change with increasing HPA price, as the price floor for the dispatch of the electrolyser moves up further (Appendix B). However, the increased HPA price brings additional revenues that markedly increase the IRR, up to 0.6 percentage points. Hence, the margin between the IRR and DHR is increased and the higher uncertainty of the hybrid powerplant can be accepted, contrary to the case with an HPA of 4 €/kg, where it did not bring additional gains.

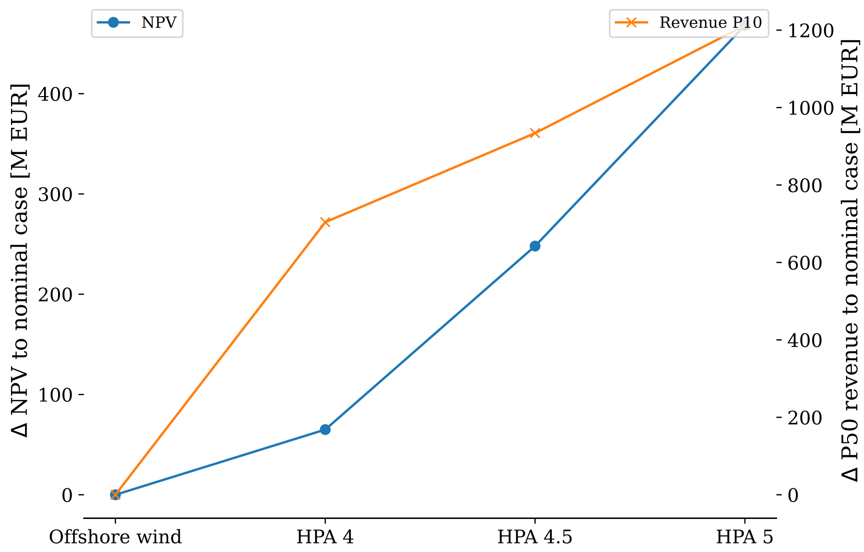

Figure 6.2: Sensitivity of the median (P50) NPV and median(P50) revenues to the HPA price. The NPV sensitivity can be read on the left axis, while the revenue sensitivity on the right. The sensitivity is presented with respect to the offshore wind case. The results include all uncertainties.

6.3. Electrolyser CAPEX

The electrolyser CAPEX was defined based on expert interviews within Vattenfall. Reflecting technological advancements in electrolysers, the CAPEX value is dynamic. As shown in Section 5.2, the electrolyser CAPEX is the main uncertainty driver due to the high cost and uncertainty. Therefore, a sensitivity analysis on this parameter is performed, by varying the CAPEX from -20% to +20% with steps of 10%, compared to the nominal CAPEX assumption. The uncertainty bands are kept the same.

Figure 6.3 introduces the results of the sensitivity analysis of the median Net Present Value and the CAPEX uncertainty (P90-P50) to the electrolyser CAPEX. The NPV sensitivity can be read on the left axis and is presented as a delta compared to the nominal CAPEX (0% in the graph). The CAPEX uncertainty sensitivity can be read on the right axis of the Figure and is again presented as a delta compared to the nominal CAPEX. The project's NPV is negatively correlated with the electrolyser CAPEX, as an increase in the CAPEX leads to a worsening NPV and vice versa. For every 10% difference in the investment cost of the electrolyser, the project NPV changes linearly by € 40 M. Thus, if a 20% reduction in CAPEX can be achieved, through for example a more mature technology, the project will see an € 80 M NPV increase.

The sensitivity analysis fo Figure 6.3 indicates that the CAPEX uncertainty is also sensitive to the nominal electrolyser estimates. A deviation of 10% is translated to a € 10 M change in uncertainty. For example, if the CAPEX is reduced by 10% the CAPEX uncertainty will be reduced by € 20 M. The reduction in CAPEX uncertainty, due to a reduced CAPEX, will allow lower contingency budgets and given the increased NPV, will make the hybrid project more competitive. The opposite is true if the best-estimates for the costs of the electrolyser are off by 10% or 20%. Then the hybrid project will appear less attractive with increased contingency requirements and a declining NPV.

This Chapter aimed at quantifying the sensitivity of the uncertainty analysis to three factors: cost of capital, Hydrogen Purchase Agreement Price and electrolyser CAPEX. These are external factors that are highly influential and work profitability drivers or barriers. If the profitability of the project changes through increased NPV and IRR, the evaluation of the uncertainty can differ from Section

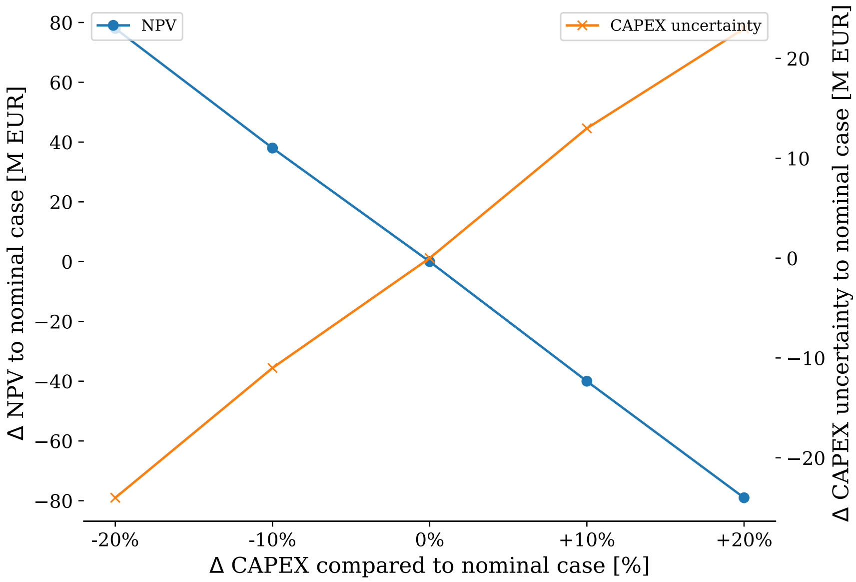

Figure 6.3: Sensitivity of the median NPV and CAPEX uncertainty (P90-P50) to the electrolyser's CAPEX. The sensitivity is presented with respect to the nominal electrolyser CAPEX assumption. The results include all uncertainties.

5.3. More specifically, the higher uncertainty of the hybrid project can be accepted if it provides substantially higher returns. This can be achieved when WACC is reduced, HPA price is increased or the electrolyser's CAPEX is lower.

The analysis not only serves as a sensitivity check to uncertainty quantification study. It is a guide on how the macroeconomic factors influence the analysis. While some parameters are outside of Vattenfall's control, the results of the analysis can be leveraged to define targets for the sensitivity variables.

7 Discussion

This research has helped quantify the impact of H2 integration on the business case uncertainty of an offshore wind farm, providing valuable insights into the uncertainty decreasing effect on revenues and the increased CAPEX uncertainty of the hybrid powerplant. First, Section 7.1 outlines the limitations of the study arising from the modelling and input data assumptions. Then, Section 7.2 discusses the real-world application of the results in the direction of uncertainty quantification and reduction.

7.1. Limitations of the study

The main limitations of the study can be attributed to the modelling and input data.

Modelling

The main limitation of the modelling in this study is the lack of transparency of the techno-economic and dispatch optimizer model due to their proprietary nature. This limits the transparency related to the cost-modelling equations and technical models (wake and loss models) are utilized. However, the study pertains to uncertainty quantification and the model is treated as a black-box with a focus only on the input uncertainties and distributions of outputs.

Secondly, the assumption of full merchant-exposure for the hybrid powerplant's revenues might limit the applicability of the studies' methodology to future tenders. If the hybrid powerplant is subject to a Power Purchase Agreement (PPA) or a Contract for Difference (CfD) scheme, the dispatch decision would have to include constraints related to the PPA delivery. Moreover, if the CfD strike price is competitive with the break-even price of H2 generation, the electrolyzer might be under-utilized. Overall, the results of the study are limited to powerplants that have full-merchant exposure to the day-ahead market.

Additional, the applicability of the results is constrained by the modelling assumptions, regarding the HPA price and electricity market. The effect of the H2-integration in terms of business-case uncertainty is specific only to the country and HPA price considered. Specifically, as analyzed in Section 5.3.2, the revenue uncertainty part of the analysis, is highly influenced by both the HPA price and the inherent volatility of the power market. Therefore, extrapolating the results of this analysis to different markets will yield different results, in particular in more volatile markets.

Input data

The accuracy of the cost and electricity-price inputs is the main limitation regarding the input data. Due to the proprietary nature of the data, dummy data were used as inputs. Even though the inputs realistically reflect Vattenfall's expectations, they are not necessarily the most up-to-date estimates. Hence, the outputs regarding the investment performance are limited by the accuracy of the input data. However, this does not affect the validity of the conclusions, as these focus on the framework to quantifying H2-integration effects on the business case uncertainty.

The final limitation of the thesis is the uncorrelated modelling of the uncertainties. The uncertain inputs are modelled as uncorrelated, while in reality some correlation exists between the variables. For example, the commodity prices can be positively correlated with fuel prices. Omitting this modelling can affect the final uncertainty evaluation of the project. To include the correlation, the correlations have to be defined and the Monte Carlo method has to be enhanced with a correlation matrix to model them.

7.2. Application of study results

As an extension to the insights of the analysis, decision-making implications are present regarding evaluation of the uncertainty for both offshore wind and hybrid projects, along with steps to mitigate those.

Offshore wind farm

Through this work, a relative ranking of the impact of each uncertainty on the project's IRR has been achieved. This allows Vattenfall to focus its efforts on mitigating the business case uncertainty for future offshore project where it has the highest impact. Already, several different hedging strategies are employed to mitigate the uncertainties arising from commodities, vessel day-rates or Adverse Weather Downtime. By applying the comprehensive methodology of the thesis, different uncertainty hedging approaches could be tested.

H2 synergies

H2 integration in the offshore wind farm increases the CAPEX uncertainty significantly. It is imperative to bring down uncertainty to make the case for H2 more compelling, from an uncertainty-perspective. In this work, the electrolyzer's and farm's investment decision coincide. Therefore, the increased uncertainty for the CAPEX is locked in, when evaluating the uncertainties. It would be interesting to consider the effect of decoupling the two investment decisions. The potential benefit of pushing the electrolyzer FID into the future would be a reduced CAPEX uncertainty, due to the better knowledge regarding the evolution of the technology. This scenario, could also help Vattenfall in its dialogue with the regulators, in situations where tenders demand H2 integration, but the economics do not support it.

Decoupling the FIDs of the offshore farm and the electrolyzer could help make investments into hybrid powerplants more attractive, by mitigating uncertainty. In case this is achieved or market conditions change in a manner that the electrolyzer provides higher revenue uncertainty, Vattenfall could employee different uncertainty metric. The framework of this thesis allows to set the P-values and evaluate uncertainty based on these. If the uncertainty profile of the hybrid plant becomes more comfortable, P80 or lower values could be utilized for the contingency reserves. Since the investments are financed on-balance sheet, there are no external uncertainty covenants imposed by lenders, that define the uncertainty ranges.

Revenue Hedging Strategies

In addition, as this is the first time for Vattenfall that revenue and cost uncertainties were considered simultaneously, the analysis can be extended to test different revenue hedging strategies. For example, the optimal capacity allocated to a Power Purchase Agreement, to achieve a set level of revenue certainty, can be investigated.

To hedge the revenue exposure of the offshore wind farm, Vattenfall will typically contract part of the generation capacity of the farm under a Power Purchase Agreement, stabilizing revenues. While this can stand true for a standalone farm, employing any revenue hedge on the hybrid powerplant, supplementary to the electrolyzer is complex. The complexity arises in two distinct ways. First, there is a direct competition between the PPA price and the electricity floor implied by the electrolyzer. Typically the contracted PPA price will be lower than the floor of H2, therefore making an additional hedge non-economical. Secondly, in case there are off-take constraints regarding baseload H2 delivery, these can be in conflict with the electricity deliver under the PPA.

Linking this observation of the limited revenue hedging capabilities of the hybrid powerplant, a possible hedging instrument can be the HPA price. Striking a higher HPA price decreases the electricity price floor. This further decouples the hybrid plants revenues from the day-ahead markets, as long as the electrolyzer is profitable.

8 Conclusions & Recommendations

8.1. Conclusions

This research quantifies how integrating a 400 MW onshore electrolyzer with a 2 GW bottom-fixed offshore wind farm affects business-case uncertainty. First, a baseline is set through application of Vattenfall's techno-economic model for an offshore wind standalone project (Section 3.1.2). Uncertainties are propagated through the techno-economic model through Monte Carlo Simulations (Section 3.1.4).

Before deciding to bid for a new tender, the main uncertainty drivers are commodity prices; steel, aluminum, copper and fuel price (Section 3.2.4). Uncertainties on the day-rates and fuel consumption of installation vessels also pose a significant challenge (Section 3.2.5). Finally, the inherent volatility of the day-ahead market is a major source of revenue uncertainty and is quantified with the methodology proposed in Section 3.2.3.

By employing Vattenfall's techno-economic model and the Monte Carlo approach, the baseline Offshore Wind case, along with the impact of uncertainties can be modelled, with the main results presented in Section 4.1 for the project without uncertainties and Section 5.1 for the impact of uncertainties.

Next the analysis extends to the hybrid powerplant with the inclusion of the electrolyzer. The electrolyzer is dispatchable and therefore, a dispatch algorithm is employed to maximize the profits of the powerplant (Section 3.1.3). The deterministic results of the hybrid powerplant are presented in Section 4.2. Then, the uncertainties of the H2-integration case are evaluated in terms of cost and revenue impact (Section 5.2). Finally, a comparative uncertainty assessment between the offshore wind project and the hybrid powerplant is given in Section 5.3.

8.1.1. How to model the business case of an offshore wind farm?

Modelling Approach

A baseline is set by modelling the offshore-wind project standalone without any uncertainties through Vattenfall's techno-economic model. The focus on this study is on CAPEX and revenues, but OPEX is also modelled in detail. 46% of the project's total CAPEX is allocated to the supply of the wind turbines and 11% to the manufacturing of the monopiles. The main costs associated with the construction are the installation of foundations and Inter Array Cabling, at 7 and 6% of the total CAPEX.

The revenues of the wind farm are calculated by applying a central day-ahead development scenario. This scenario reflects a feature with increased renewable penetration coupled with increased demand from electrification & electrolysis, leading to lower price-cannibalization effects and moderate day-ahead prices. Using the power-price inputs and after a detailed Annual Energy Production calculating amounting for wake effects and electrical losses, the revenues per annum are calculated.

Economic Performance

The application of the technoeconomic model indicates that the offshore wind project can go ahead, as its Internal Rate of Return (IRR) meets the pre-defined Hurdle Rate of 8%, which has been calculated in Section 3.2.2. Additionally, the project has a positive Net Present Value of 543 M € and the Levelized Electricity Cost has been calculated at 43.9 € /MWh. With the given cost structure and expectations for the development of the market, this project can be further put forward for a bid decision.

8.1.2. What are the main uncertainties in the business case of an offshore wind project?

Sources of uncertainty

Since the project is investable with the point-estimate for CAPEX and revenues, its economic performance has to be investigated under the presence of uncertainties. While the project is scrutinized for a bid decision, various economic parameters are uncertain, either because they are subject to market changes or because negotiations with suppliers are not finalized. Since the focus of the uncertainty quantification study is on the costs and revenues, uncertainty related to the Annual Energy Production of the wind farm has not been considered, as the effect is considered minor to cost and revenue uncertainty. In summary, the uncertainties quantified in this thesis were :

1. Commodity Prices: Steel, Aluminum, Copper, Marine Gas Oil
2. Vessel day-rates & fuel consumption
3. Power-market volatility

By defining triangular distributions, with a mode equal to the deterministic value, the impact of these uncertainties is quantified. Through the Spearman rank correlation, the uncertainty drivers are defined, based on their impact on the IRR variability. The key driver is revenue due to the power market volatility, with a more than three-fold impact compared to the second driver, the foundation installation. The installation of the IAC and wind turbines, and the manufacturing of the foundation rank similarly, followed by the uncertainty in the wind turbine supply costs.

Impact of uncertainties in the economic performance

Translating the impact of uncertainties to economic performance is done by a statistic analysis of Monte Carlo results. Through the Monte Carlo analysis, the cost, revenue and overall economic performance uncertainty can be quantified. Including the cost uncertainties mentioned above leads to a CAPEX uncertainty of € 29 M. Quantifying the CAPEX uncertainty is crucial, as this estimate of the investment cost uncertainties will inform the project's contingency budget. On the revenue side, it is the first time that an uncertainty quantification methodology was applied for revenues, yielding significant results. The expected uncertainty in revenues is in the order of € 70 M rendering it the main uncertainty driver.

Overall, by performing the uncertainty quantification study for the offshore wind farm, the expected contingency budget and revenue-downside potential is calculated. As an extent, the economic performance of the project is evaluated under uncertainty. Strikingly, the median IRR of the project is found to be 0.1 percentage points below the deterministic simulations, leading to a project that is not meeting the hurdle rate.

8.1.3. How to model the business case of an offshore wind farm with hydrogen integration?

Modelling Approach

The hybrid powerplant cost is model by including the electrolyzer's CAPEX and OPEX value in the techno-economic model of the offshore wind farm. Additionally, through the Dispatch Optimization algorithm, the revenues of both wind farm and hydrogen are calculated, based on the central scenario and a Hydrogen Purchase Agreement price of 4 € /kg. The HPA has no minimum or baseload supply requirements and the electrolyzer is connected to a gas grid, that can absorb all produced H2.

Economic Performance

In terms of economic performance, the inclusion of the electrolyzer increased the median IRR from 8.0% to 8.1% compared to the baseline case. This increase signifies that the additional cost of the electrolyzer is balanced by the additional revenues from hydrogen sales, with an incremental improvement.

The inclusion of electrolyzer **significantly increases the revenues of the wind farm** by providing a floor to the minimum electricity price, but simultaneously increases the CAPEX and OPEX due to the high costs of the electrolyzer. Ultimately, the synergy of H2 and offshore wind can increase the Internal Rate of Return, but the marked revenue increase is outweighed by the large cost of the electrolyzer.

8.1.4. What are the main uncertainties in the business case of an offshore wind project with H2 synergy?

Sources of uncertainty

In addition to the uncertainties linked to the offshore wind farm, the investment in the hybrid power-plant comes with significant electrolyzer CAPEX uncertainty. The investment cost of an electrolyzer cannot be accurately predicted due to the limited experience with multi-MW projects. Therefore, the nominal CAPEX estimate is accompanied by an uncertainty band in the order of -30%. Based on the Spearman ranking of the uncertainties, the electrolyzer's CAPEX uncertainty is now the dominant source of all uncertainties, even outweighing revenue uncertainty. Importantly, the electrolyzer CAPEX outweighs every other cost uncertainty by at least three-fold.

Impact on economic performance

The inclusion of the electrolyzer increases the CAPEX uncertainty to € 123 M while the revenue uncertainty stands at € 52 M. Despite the increase in CAPEX uncertainty, the outcomes of the project remain contained, with 80% of the results being within 0.2 percentage points of the median IRR.

8.2. Main conclusion

The central research question of the thesis was : *How are uncertainties in the business case of an offshore wind project affected by the addition of hydrogen plant?*

The findings of this work indicate the integration of a 400 MW electrolyzer in a 2 GW offshore wind farm increases the business-case uncertainty, as the increase in the cost-uncertainties from the electrolyzer outweigh the revenue uncertainty reduction.

In terms of CAPEX, the inclusion of the electrolyzer increases the CAPEX uncertainty by € 94 M or more than three times the cost uncertainty of the offshore wind project. This is a significant uptake of uncertainty and will have to be accounted for in increased contingency budgets for the project. Such an uptake in risk can hinder decision-makers to positively decide for H2 integration projects.

In terms of revenues, H2 integration has a limited uncertainty reduction effect on the order of € 18 M. Due to the binary dispatch of the electrolyzer (full or no power), the limited volatility of the Swedish market and the Hydrogen Purchase Agreement price assumed, the electrolyzer primarily adds to the farm's revenues but does not increase revenue certainty considerably. If in the long run the day-ahead market becomes more volatile and expensive, the uncertainty reduction effect of the electrolyzer will be increased.

Finally, in terms of Internal Rate of Return the projects look comparable, with hydrogen producing a marginal 0.1 percentage point increase in the median IRR. The offshore project is more certain as evaluated by this aggregate metric, indicating that the increase in CAPEX uncertainty outweighs the impact of the revenue uncertainty decrease.

Overall, the methodology allows to compare the effect of hydrogen integration in the business case uncertainty of an offshore wind farm. In the uncertain environment offshore wind is currently through, such a tool can be utilized by Vattenfall to continuously assess individual projects with changing inputs. It is concluded that the increase in cost uncertainty induced by the costs of the electrolyzer outweigh the gains in revenue certainty, with the offshore project appearing marginally more certain. Given the two project produce similar investment returns, accepting the increased uncertainty of the hybrid powerplant is non-economical. However, if the Hydrogen Purchase Agreement price increases, or the electrolyzer CAPEX reduces, the analysis could deem the hybrid project more economical.

8.3. Recommendations

To further enhance the results of this analysis, five recommendations for further research are proposed. The first and second recommendations regard the refinement of the inputs, specifically the commodity price exposure and revenue volatility of the day-ahead markets. The third recommendation suggests the inclusion of Annual Energy Production uncertainty. The fourth recommendation pertains to the generalization of the study to further countries and markets. Finally, it is recommended to deploy the methodological framework to different hybrid configurations, including Battery Energy Storage Systems.

8.3.1. Detailed exposure calculation to commodity prices

Translating the commodity price volatility to cost uncertainties for turbines and other components, is performed through exposure calculation to commodity prices, using the mass of the commodity involved. However, this is a simplified calculation and a more nuanced calculation is required for accurate uncertainty estimation. The exposure depends both on the volatility of the underlying commodity, contractual provisions and hedging instruments employed. For example, instead of assuming full exposure of the wind turbine to movements of the steel price, any provisions in the contracts between Vattenfall and the WTG supplier that protect against steel-price volatility should be included in the exposure calculation. In this way, the exposure calculation will be more detailed.

8.3.2. Revenue uncertainty quantification

To further tune the inputs of the Uncertainty Quantification study, the measure of the volatility in the day-ahead markets should be fine tuned. In this study, the difference between a central and low scenario was utilized as a proxy for market volatility, as no other measure of the forecasted volatility was available. The pitfall of this method is that the two different market scenarios might predict different day-ahead curves and using this difference could misrepresent uncertainty in specific timelines. Hence, a detailed uncertainty quantification study shall be performed at the level of the electricity market model, to derive an uncertainty range for the day-ahead forecasts. These results could be then used as inputs for the Uncertainty Quantification study at the project-risk.

8.3.3. Annual Energy Production uncertainty quantification

Uncertainty in Annual Energy Production (AEP) is often considered in uncertainty quantification studies for offshore wind. In this study the focus was on cost and revenue uncertainties, therefore (AEP) uncertainty was not considered. For completeness of the analysis, AEP uncertainty shall be included as an uncertainty source in a further study. With the inputs currently utilized, the two projects perform similarly in terms of uncertainty. Including AEP uncertainty might affect the comparison of the projects. Similarly to revenue uncertainty reduction through the inclusion of the electrolyzer, a hybrid powerplant could reduce AEP uncertainty. Outside the uncertainty in meteorological conditions, AEP can be uncertain due to curtailment of the wind farm. The hybrid powerplant will have less curtailment due to the capability to produce hydrogen in times where curtailment (technical or economical) is required, reducing the impact of AEP uncertainty.

8.3.4. Geographic & market diversification

The proposed methodology to quantify the impact on the business case uncertainty of an offshore wind by the addition of a hydrogen plant is global. However, the inputs for costs, wind production profile and day-ahead market correspond to a specific geography and market conditions. Hence, performing the same study would allow to test how applicable the conclusions are in varying market conditions. Since hydrogen is an emerging technology, costs develop rapidly, both as absolute costs and uncertainties. Therefore, Vattenfall can leverage the framework developed in this thesis, to continuously evaluate the effects of policy and technology developments in a hybrid powerplant. Based on past experiences with emerging technologies, like offshore wind, initial projects where accompanied by large uncertainties leading to cost overruns. As the technology matures and more project-experience is gained, the uncertainty is reduced and the projects become more financially feasible. Since each country has a differentiated market and policy framework, continuously using the framework allows for decisions on where and when it is optimal t o invest.

8.3.5. Extension to Battery Storage Energy Systems

A final recommendation is to apply the uncertainty quantification framework to a hybrid project with Battery Energy Storage System (BESS) instead of an electrolyzer. Batteries are dispatched different compared to hydrogen, taking advantage of arbitrage opportunities in the power markets and providing ancillary services. Therefore, BESS can provide more pronounced revenue uncertainty reduction. Moreover, more experience with installing and operating BESS exists. Thus the cost uncertainty will be significantly lower compared to the electrolyzer. In the case of BESS, it would be interesting to study the cost and revenue uncertainty trade-off and compare its performance to a hybrid park with an electrolyzer. The methodology is robust and is technology-agnostic and can applied in different hybrid configurations.

Acknowledgments

The past 7 months have been an immense learning experience, exposing me to several different fields: from financial analysis of renewable energy to the difficulties faced during installation of an offshore wind farm. These opportunity would not have been realized, was it not for a lot of people that supported me during this journey.

From TU Delft, I am first extending my gratefulness to Prof. Stefan Pfenninger, who served as Chairman of the thesis committee. Stefan, thank you for giving me this opportunity to work with Vattenfall on this exciting topic and for your guidance. Secondly, I would like to thank Prof. George Lavidas, for accepting to be a member of the examination committee. Finally, I would like to thank Dr. Bart Ummels. I met Bart a year prior to starting the thesis during an offshore wind farm tour. I was amazed by his width of knowledge and his ability to explain complex concepts in a simple manner. I already knew that I would like to work with him for my thesis. Bart, thank you for the discussions, the guidance and for being more than a supervisor, a mentor for me.

This project could not have happened without my colleagues and supervisor in Vattenfall. I got the amazing opportunity to meet Dr. Hannah Nevailanen and to have her as my supervisor. Hannah, thank you for your immense support and guidance, advising not only on high-level topics, but being involved in my daily struggles with the technicalities of the models. Thank you for taking time of your busy schedule to help me snap out of tough dilemmas and providing a fresh perspective. Then, I would like to thank the manager of the System Design team, Georgios Kaloritis, for helping realize the project and providing support always when needed. I would also like to thank my colleague from System Design Martiene Ubbens, for all the nice discussions we had, for reading my thesis and providing very detailed feedback. Also, everyone in System Design team, thank you for hosting me and thanks for all the nice memories. It was brilliant working with the team!

In the end, I would like to thank my family for giving me the opportunity to purse an MSc in the Netherlands. My friends in Delft and Greece for all their support and finally my partner Maria, for bearing together with me for these two years in the Netherlands.

Ioannis Stratikis
08/07/2025
Delft, the Netherlands

Appendices

A

WACC Scenarios

Company	Listed in	β
Electricite de France	France	1.01
Enel	Italy	0.97
Iberdrola	Spain	0.73
SSE	UK	0.75
Orsted	Denmark	1.02
RWE	Germany	0.75
Average	–	**0.87**

Table A.5: β values of major European energy and utilities companies, which are publicly traded. *Data from https:// www.infrontanalytics.com*

Scenario 1 30:70 gearing ratio				
Interest Rate Scenarios	Euribor +150BPS	Euribor +50 BPS	Euribor -50 BPS	Euribor +300 BPS
Cost of Debt	3.9%	2.9%	1.9%	5.4%
Tax rate	25.0%	25.0%	25.0%	25.0%
After Tax Cost of Debt	2.9%	2.2%	1.4%	4.1%
Cost of Equity	7.4%	7.4%	7.4%	7.4%
WACC (after tax)	**6.1%**	**5.8%**	**5.6%**	**6.4%**

Table A.1: Scenario 1: 30:70 gearing ratio and four different developments of interest rates

Scenario 2 40:60 gearing ratio				
Interest Rate Scenarios	Euribor +150BPS	Euribor +50 BPS	Euribor -50 BPS	Euribor +300 BPS
Cost of Debt	3.9%	2.9%	1.9%	5.4%
Tax rate	25.0%	25.0%	25.0%	25.0%
After Tax Cost of Debt	2.9%	2.2%	1.4%	4.1%
Cost of Equity	7.4%	7.4%	7.4%	7.4%
WACC (after tax)	**5.6%**	**5.3%**	**5.0%**	**6.1%**

Table A.2: Scenario 2: 40:60 gearing ratio and four different developments of interest rates

Scenario 3 50:50 gearing ratio				
Interest Rate Scenarios	Euribor +150BPS	Euribor +50 BPS	Euribor -50 BPS	Euribor +300 BPS
Cost of Debt	3.9%	2.9%	1.9%	5.4%
Tax rate	25.0%	25.0%	25.0%	25.0%
After Tax Cost of Debt	2.9%	2.2%	1.4%	4.1%
Cost of Equity	7.4%	7.4%	7.4%	7.4%
WACC (after tax)	**5.2%**	**4.8%**	**4.4%**	**5.7%**

Table A.3: Scenario 3: 50:50 gearing ratio and four different developments of interest rates

Scenario 4 60:40 gearing ratio				
Interest Rate Scenarios	Euribor +150BPS	Euribor +50 BPS	Euribor -50 BPS	Euribor +300 BPS
Cost of Debt	3.9%	2.9%	1.9%	5.4%
Tax rate	25.0%	25.0%	25.0%	25.0%
After Tax Cost of Debt	2.9%	2.2%	1.4%	4.1%
Cost of Equity	7.4%	7.4%	7.4%	7.4%
WACC (after tax)	**4.7%**	**4.3%**	**3.8%**	**5.4%**

Table A.4: Scenario 4: 60:40 gearing ratio and four different developments of interest rates

B
Dispatch decision example

The decision central to the dispatch of hydrogen from the hybrid powerplant is summarized below. Assuming the electrolyzer (PEM + BoP) requires 0.06 MW of electricity for every kg of H2 output $\eta_{electrolyzer} = 0.06 MW/kg$, it is profitable to produce hydrogen when :

$$Revenue_{H2} \geq Cost_{H2,production} \Rightarrow P_{H2} \geq \frac{P_{electricity}}{\eta_{electrolyzer}}$$

Solving for the electricity price and assuming the hydrogen is always sold at the same price of 4 €/kg due to the HPA, $P_{H2} = 4$ €$/kg$:

$$P_{electricity} \leq \frac{P_{H2}}{\eta_{electrolyzer}} \Rightarrow P_{electricity} \leq 66 \text{ €}/MWh$$

The higher the HPA price agreed, the higher the break-even electricity price, as illustrated on Table B.1. This means that there is more margin to produce hydrogen and the electrolyzer can be more utilized.

HPA price (€/ kg)	4	4.5	5
Electricity break-even price (€/MWh)	66.6	75	83.3

Table B.1: Electricity break-even price sensitivity to HPA price

C
Monte Carlo convergence

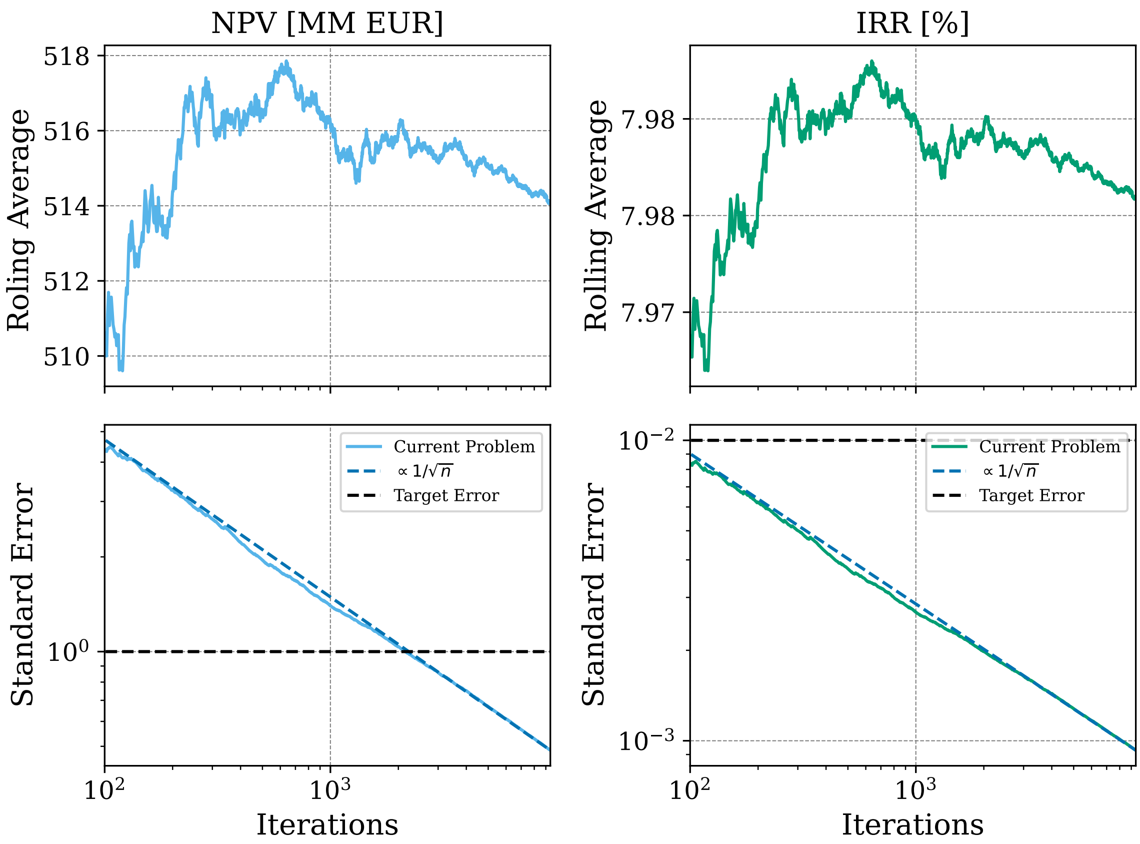

Figure C.1: Rolling Average and Standard Error of the Net Present Value and Internal Rate of Return convergence, for the offshore wind case. 10000 simulations were performed.

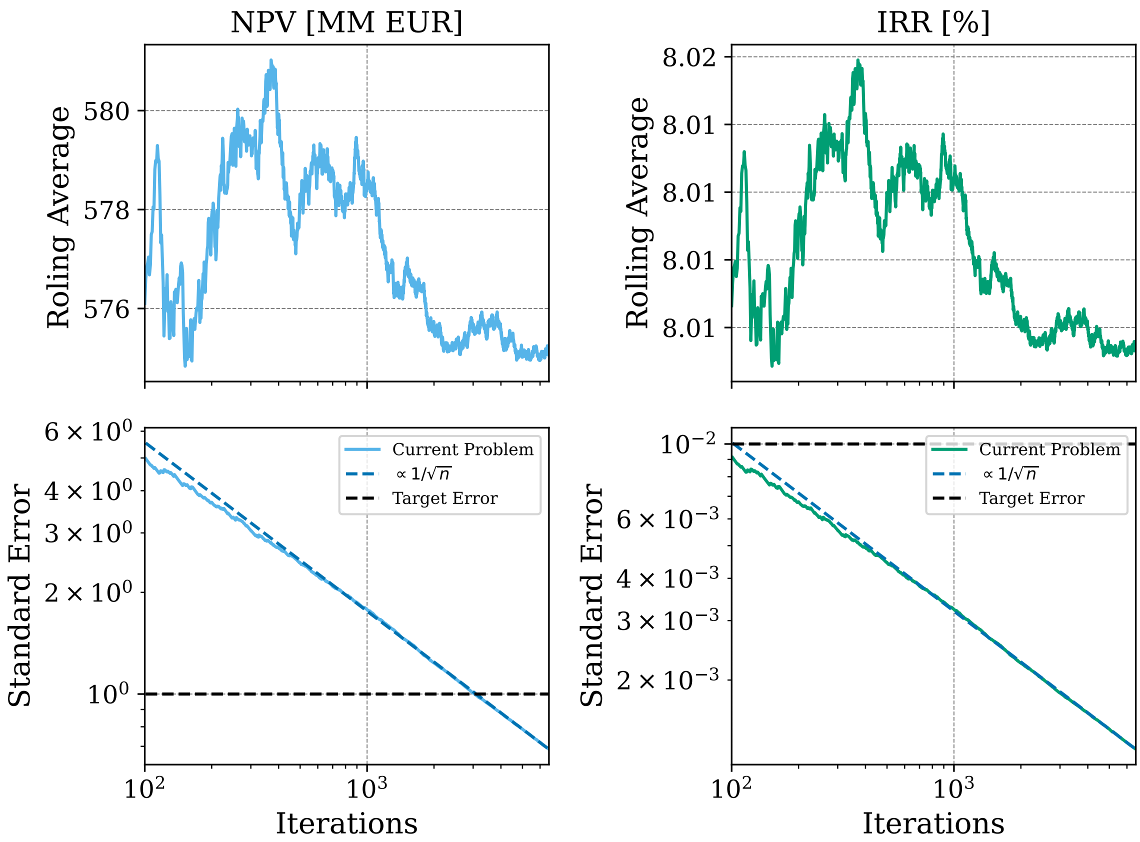

Figure C.2: Rolling Average and Standard Error of the Net Present Value and Internal Rate of Return convergence, for the H2 integration case. 10000 simulations were performed.

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