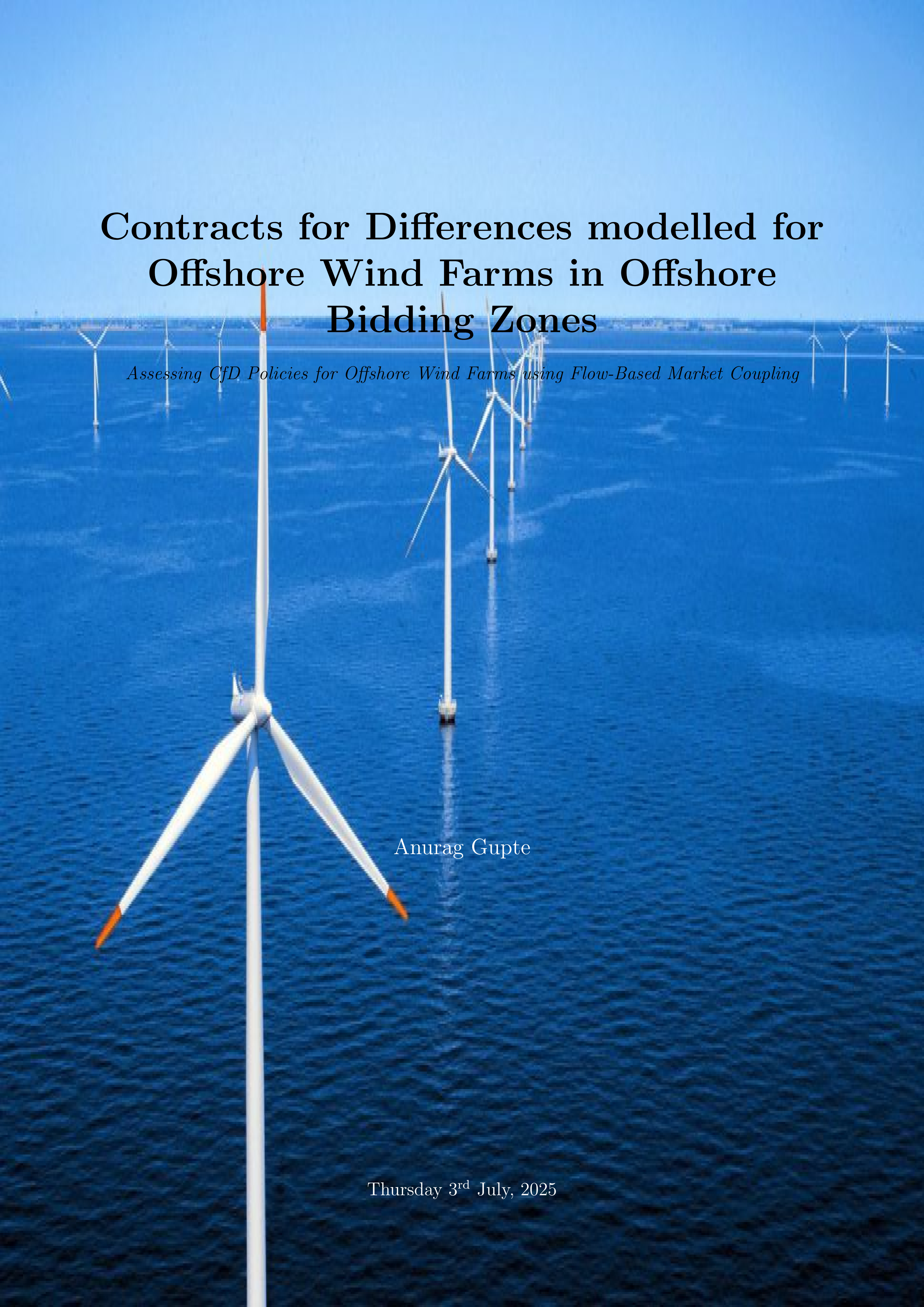

Contracts for Differences modelled for Offshore Wind Farms in Offshore Bidding Zones

Assessing CfD Policies for Offshore Wind Farms using Flow-Based Market Coupling

Anurag Gupte

Thursday 3rd July, 2025

Thesis report

by

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Technology Policy and Management · Delft University of Technology

Preface

This thesis marks the end of my academic journey at TU Delft as I graduate with a Master's in Sustainable Energy Technology. The last two years have been years of massive personal and academic growth. I entered TU Delft intending to become a wind energy engineer, but soon found myself drawn to the complexities of energy markets and policy. I never thought as a mechanical engineer that I would be working on energy markets and policy. I am deeply grateful to all the professors who helped shape my journey throughout my master's.

I would like to thank my first supervisor, Kenneth Bruninx for his expert guidance and unwavering support throughout the thesis. He was always available to provide his precious critique and spent time brainstorming with me to find solutions when I was stuck. Diving into a topic as complex as flow-based market coupling without having previous knowledge of coding or economics would have been impossible without his help. I would also like to thank my second supervisor, Ozge Okur, for providing important feedback and being a second set of eyes for my thesis, which improved the quality of my work.

Most importantly, I would like to thank my parents for providing unconditional love and support to me. All the way from financially supporting this passion of mine to actively advising me on important life matters. I am eternally indebted to my family. This achievement would be impossible without them. Last but not least, I would like to extend my deepest gratitude towards my friends, here in Delft and back home, for always having my back through happy and tough times. The two years here were nothing but joyful due to some of the amazing people I met here. I would like to offer my apologies for my absence from many social events in the last few months, but it was they that helped me march on to conclude this chapter of my life.

This thesis began with a passion for offshore wind, and through the lens of energy markets, it deepened my understanding of the complexities of the European energy system. Learning to code in Julia was initially a challenge, but it turned into one of the most rewarding experiences of my academic journey as I developed and worked with the model. There was a significant practical relevance of the project, which motivated me further. This topic is vast and closely connected to the future of offshore energy systems. The more I explored it, the more I realised how much more there is to uncover. I tried to do my best to write as concisely and simply as I could to translate the results of my model into actionable insights. I would like to thank anyone who takes the time to read this thesis. If you have any questions or would like to discuss the topic further, please feel free to reach out.

Anurag Gupte
5993792
3 July, 2025

Summary

As Europe transitions hybrid offshore grid models, OBZs have emerged as a promising market design for integrating offshore wind. The large-scale offshore wind buildout planned in the North Sea. In such a landscape, the wind farm developers are exposed to significant risks and uncertainties regarding revenues. There is a requirement for policy intervention in OBZs to ensure there is enough incentive for developers to invest in these projects

TSO and market players have recommended numerous policy schemes, but CfDs in particular are gaining traction. The literature regarding such CfD schemes was examined in the thesis. The literature, however, shows limited research on operationalising such CfD designs in OBZs and using FBMC to study their impact on the behaviour of the wind farms. There are certain inefficiencies and distortions triggered by the CfD policies; however, they are not quantified in great detail. Moreover, the study on their impact on the system behaviour as a whole is limited.

Reasearch Question and Methodology

The primary objective of this thesis is to explore the different CfD policies prominent in the literature and deploy them for Offshore Wind Farms in Offshore Bidding Zones. The aim is to study the rational response of OWF operators in the bidding process within an OBZ environment and to ascertain the risks involved in OBZs. The following study is aided by answering the main research question as follows:

How can Contracts for Difference (CfD) schemes be designed and implemented in offshore bidding zones to incentivise investment in offshore wind farms, and how do they influence operational behaviour and technology preferences?

The main research question is further broken down into four sub-research questions. These are specifically designed to refer to the CfD policies discussed in the literature from an OBZ context, quantify the challenges faced by existing CfD policies, identify the operational inefficiencies in the day-ahead market triggered by CfD choices, and examine whether a CfD design triggers technology biases.

Research Methodology

The research consists of two parts: the first is a qualitative literature survey to define the research gaps and explore the CfD policies prominent in literature. The second involves quantitative model development, where a simulation model is built in Julia to replicate the FBMC process using three onshore zones and an OBZ. The FBMC model is based on the work of (Kenis, Delarue, Bruninx, & Dominguez, 2023). A decision block is incorporated for OWF operators, who have complete information about market clearing and price formation. Based on the CfD policy being applied, they decide the amount of power to bid into the market.

The model is designed to evaluate the performance of various CfD policies, including both production-based and non-production-based designs. It integrates FBMC, generator bidding logic, and revenue

optimisation under a range of realistic grid scenarios. These scenarios account for differences in wind profile alignment, turbine technology, and the presence of offshore electrolysers.

The simulation follows a sequential process: a scenario is first defined, followed by market clearing for the D-2 base case and the D-1 day-ahead case. The OWF then reacts to the resulting market price and makes a bidding decision based on the CfD policy in place. This decision is reflected in a new round of market clearing, and the day-ahead step is recalculated. The updated price is then fed back to the OWF decision block, prompting a possible revision of the initial bid. This loop continues until the model converges to a stable solution.

Each scenario tests different CfD policies explored in the literature. A set of metrics is developed to compare the results across all cases within each scenario.

Results and Conclusion

The results show that while production-based CfDs help increase revenues, they leave OWFs exposed to volume risk and encourage overbidding, often leading to curtailment and system inefficiency. Financial CfDs mitigate both price and volume risk but create new behavioural distortions. Locational and technological heterogeneity further amplifies inequality in revenue distribution, particularly when references are not adjusted for performance or grid position. Scenario analysis also demonstrates that integrating flexible demand-side agents like offshore electrolysers can reduce capacity allocation curtailment and improve price stability.

The findings highlight that CfD designs must account for the physical and technological diversity of offshore assets. Policy recommendations include using location-based references, grouping similar technologies under the same contract terms, and modelling behavioural responses under uncertainty. A more nuanced approach to CfD implementation is needed to support long-term investment while preserving system efficiency and fairness in future offshore electricity markets.

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List of Abbreviations

AAP	Available Active Power
AC	Alternating Current
AHC	Advanced Hybrid Coupling
CAPEX	Capital Expenditure
CfD	Contract for Difference
CWE	Central Western Europe
DA	Day-Ahead
DC	Direct Current
DSM	Demand-Side Management
D-0	Redispatch (Day of Delivery)
D-1	Day-Ahead Market Clearing (1 day before delivery)
D-2	Base Case (2 days before delivery)
ENTSO-E	European Network of Transmission System Operators for Electricity
FBMC	Flow-Based Market Coupling
FAV	Final Adjustment Value
FRM	Final Reliability Margin
FTR	Financial Transmission Right
GSK	Generation Shift Key
HVDC	High Voltage Direct Current
IEA	International Energy Agency
NSWPH	North Sea Wind Power Hub
NTC	Net Transfer Capacity
nPTDF	Nodal Power Transfer Distribution Factor
zPTDF	Zonal Power Transfer Distribution Factor
OBZ	Offshore Bidding Zone
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
PDC	Price Duration Curve
PTDF	Power Transfer Distribution Factor
RAM	Remaining Available Margin
RES	Renewable Energy Source
SHC	Standard Hybrid Coupling
TSO	Transmission System Operator

MW	Megawatt (1 MW = 10^6 W)
MWh	Megawatt-hour (energy)
kW	Kilowatt (1 kW = 10^3 W)
kWh	Kilowatt-hour (energy)
GWh	Gigawatt-hour (1 GWh = 10^3 MWh)
€/MWh	Euro per Megawatt-hour (price of energy)
€/MW	Euro per Megawatt (capacity cost)
€	Euro (currency)
h	Hour (time)
min	Minute (time)
s	Second (time)

Contents

1 | Introduction

1.1 Context

The European Union climate targets stipulate that the European Union should reduce 40% of its emissions by 2030, in line with the Paris Agreement (COM, 2018). This requires a large effort to transform the current energy systems into carbon-neutral and renewable alternatives (Krumm, Süsser, & Blechinger, 2022). However, the long-term vision of the EU is to achieve net zero greenhouse gas emissions by the year 2050 (Commission, 2018). To achieve this goal, the European Commission suggests increasing the renewable energy being consumed to 32% of the final energy consumption of the EU (Commission, 2018). To achieve these targets, the Netherlands has signed multiple agreements to deploy and develop carbon-free energy alternatives. Among the various renewable energy sources being developed, offshore wind is viewed as a viable option for reducing greenhouse gas emissions. The Dutch government has sanctioned a roadmap for significant investment in offshore wind, aiming for an installed capacity of 21 GW by the year 2031 (Macquart, Kucukbahar, & Prinsen, 2023). The installed and tendered capacity in the North Sea by the Netherlands is 6.3 GW as of 2023, while the target for the year 2030 is 21 GW. This emphasises the effort required to install offshore wind energy to meet the capacity targets (Macquart et al., 2023).

The North Sea serves multiple purposes, including fishing, shipping (with several key EU and global ports located along its coast), as well as oil and gas extraction, mining, military operations, and protected nature reserves (Zaken, 2017). Offshore wind farms (OWFs) must be developed in compliance with these existing uses and restrictions. Due to the shallow waters and favorable wind conditions in the North Sea, coupled with limited available maritime space, many OWFs are being pushed further offshore. This increases the complexity and requires expensive transmission as stated in (Weichenhain, Elsen, Zorn, & Kern, 2019). To address these questions, hybrid projects are proposed as a method to integrate the large amount of wind being sanctioned in the North Sea. Hybrid projects are relevant in an offshore environment because they integrate power generation with transmission operations, allowing both to function together efficiently and reducing spatial and financial costs. This results in a cost-effective and space-efficient solution while also providing interconnection between various electricity markets in the EU, aiding the EU's internal energy market.
Hybrid projects help reduce the need for extensive offshore cabling and converter infrastructure (Thema, 2020), thereby lowering the costs of offshore projects. Using interconnectors ensures a space-efficient usage of maritime areas, reducing the environmental impacts of offshore wind development. Furthermore, the reduced need for cables would reduce the number of landing points that would otherwise be required for radially connected Offshore Wind Farms (OWF) (NSWPH, 2021). Additionally, this enables higher interconnection capacity in the electricity markets in Europe, as a result of which, there is an influx of low-priced energy in the market. This leads to a more efficient energy dispatch and low system costs for the dispatched energy(Thema, 2020). Increased market coupling results in a security of supply to the interconnected markets and countries (NSWPH, 2021). Additionally, Offshore Network Development Plans (ONDP) in the North Sea have identified the potential to have offshore hybrid projects that integrate multiple energy sectors like hydrogen (ENTSO-E, 2024a).
The countries in the North Sea region have signed the North Seas Energy Cooperation declaration in 2016, wherein the involved countries, (Ireland, the United Kingdom, France, Belgium, the Nether-

lands, Luxembourg, Germany, Denmark, Norway and Sweden) agree to cooperate and contribute to develop offshore wind energy in the North Sea. The countries mentioned earlier have hybrid projects under consideration in the Ten-Year Network Development Plan (TYNDP) 2024 (*TYNDP 2024 Project Collection*, n.d.). This encourages the transmission system operators and also the offshore wind developers to be the early movers in hybrid projects (Weichenhain et al., 2019). Clarity is needed on the market setup early on in the development of hybrid projects for ensuring a reliable and stable climate for all the stakeholders (NSWPH, 2021).

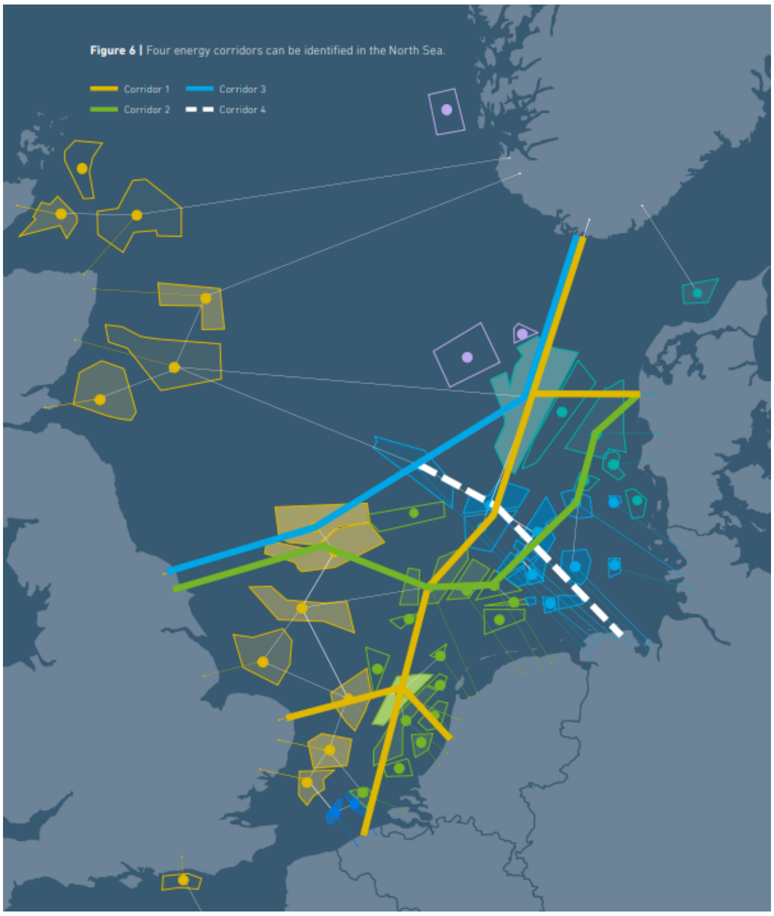


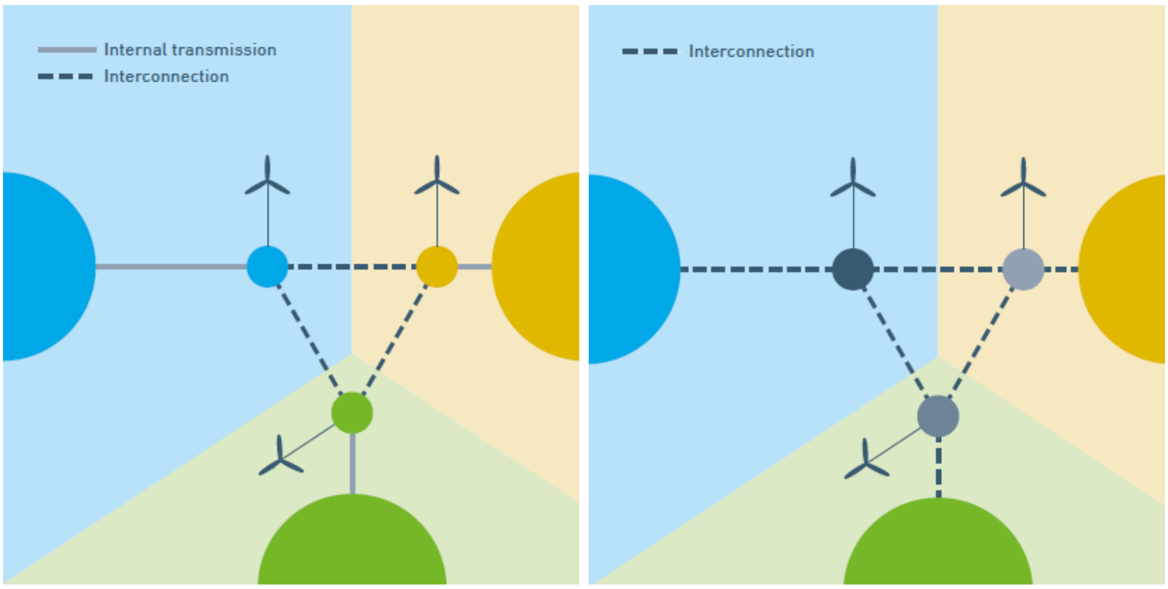
Figure 1.1: Energy corridors for offshore wind projects
(Hub, 2024)

Therefore, developing a market setup in line with European principles is of considerable importance for deploying hybrid projects. Two of the most prominent market design concepts in the EU currently are Home Markets and Offshore Bidding Zones (OBZ) (ENTSO-E, 2020). Home markets refer to the traditional approach where the offshore wind farms are connected to the home country's bidding zone (Lüth, Werner, Egging-Bratseth, & Kazempour, 2024). Therefore, in this case, the wind farms submit their bids into the bidding zone associated with their home markets. The generators dispatch the power to the bidding zone associated with the mainland and consequently receive the price of the bidding zone, which is their home market. The connection of the OWF is virtually split into two parts, one which serves as the connection between the generator and the HM, while the other is the interconnection between the power plant and the foreign market (ENTSO-E, 2020). In the HM setup, the injection made by the generator is classified as internal flow (Thema, 2020).

Transmission System Operators (TSOs) are required to ensure that at least 70% of the cross-border interconnection capacity (Minimum Available Margin, minRAM) is available for EU member states. This is in accordance with Article 16, paragraph 8 of the EU Regulation on the Internal Market for

Electricity (2019/943). Therefore, the rule implies that the cross-zonal flow should always have 70% capacity available for exchanges. Unless the cables to the mainland for a hybrid project are separate from the interconnector lines or the cables are oversized to accommodate the internal flow from the generator to the HM, the OWFs have to curtail wind to allow the cross-zonal flow. This regulation under the current policy framework leads to an inefficient social outcome as the more expensive foreign power has priority over cheaper wind energy. The Article 63 of Regulation (EU) 2019/943 provides an exemption to overcome this particular issue for offshore wind farm generators. The exemption offered to the generators is either for new generators or generators that have significantly increased their capacity. It offers short-term guarantees, however, it leads to dispatch inefficiencies and discourages investment due to a lack of clear policy assurances for the future (Thema, 2020).

To address the inefficiencies mentioned above, a separate bidding zone, called the Offshore Bidding Zone, is established for offshore hybrid projects, with its own wholesale electricity price (Thema, 2020). Offshore Bidding Zones involve the creation of a dedicated bidding zone where all the offshore wind farms submit their energy bids. The energy is dispatched based on the market coupling with the connected onshore bidding zones (Tosatto, Beseler, Østergaard, Pinson, & Chatzivasileiadis, 2022). The OBZ setup is compliant with the 70% ruling as the interconnection cables are classified as cross-zonal cables therefore being available for cross-zonal trading. (TenneT, 2024). The dispatch solution tends to lead to a socially optimal outcome, as the power always flows towards the region that needs it the most (NSWPH, 2021). The price formation in the OBZ generally depends on the low-priced region in its vicinity to which an uncongested path exists.
Much of the literature states that OBZs are more efficient in dispatch and capacity allocation and, therefore, are preferred to the HM model (NSWPH, 2021). ACER and CEER recommend the integration of offshore hybrid projects using a market setup of OBZs, however, it recommends the European Commission to further analyse the possible concerns and their mitigation measures (ACER, 2022). The report highlights that OBZs face reduced and uncertain revenue for OWFs due to lower market prices, misaligned incentives from congestion income allocation, regulatory gaps in accommodating hybrid project structures, and technical challenges of connecting to multiple onshore markets with differing rules. These issues call for further regulatory clarity and targeted support mechanisms to enable effective OBZ implementation. Although an OBZ setup has advantages over the HM setup, there are challenges associated with OBZ that need to be addressed.



(a) Home Market (b) OBZ

Figure 1.2: Comparison between Home Market and OBZ models
(NSWPH, 2022)

1.2 Problem Definition

There is limited demand in the offshore bidding zone which causes the price formation in the bidding zone to be determined by the neighbouring zone to which an uncongested path exists (Nieuwenhout, 2022). If the transmission capacity to the neighbouring zone with the highest price is available, the OBZ will adopt that zone's price. However, if the transmission lines to the highest-price zone are congested, the OBZ will take the price of the next highest-priced neighbouring zone. The market coupling is performed in the offshore bidding zones to determine the price, which depends on the neighbouring onshore markets. While all market zones experience some level of price uncertainty due to network constraints, the OBZ faces a structurally different form of price risk. Onshore zones typically have multiple supply and demand actors and a diversified generation portfolio. This helps them to stabilise internal price formation even under congestion. In contrast, the OBZ has no local demand and is heavily dependent on cross-zonal transmission capacity to access the market. This makes the OBZ more vulnerable to grid congestion, which can reduce its market-clearing price to zero. The OBZ's price is not a direct function of local supply-demand balance. It is instead an outcome of neighbouring zones' capacity and pricing, making its revenue stream far less predictable.
When the limit of transmission capacity is reached, the price in the OBZ falls to 0 €/MWh, with the frequency of these price collapses depending on the transmission grid dimensions (Kenis et al., 2023). It is observed that the average price for the OWFs is lower under the OBZ setup compared to the HM setup (Kenis et al., 2023). While this is effective in sending signals to the transmission operator for congestion management, it results in the transfer of welfare from the generators to the transmission operators. This risk can deter investors from investing in OWFs, as the uncertainty in pricing is significant without policy intervention.

The generators are also exposed to volume risks related to competition for the interconnector capacity and also competition from the onshore power generators (Elia & Orsted, 2024). Since the allocation of the capacity is through market coupling and the offshore generators do not receive priority, they are exposed to volume risks. However, due to the competitive nature of the offshore wind bids, this risk is not as significant as the price risk (Elia & Orsted, 2024).
In an OBZ, the generators receive lesser revenues than a Home Market solution. On the other hand, transmission owners get greater revenues in OBZs due to congestion, as seen in (Thema, 2020). Therefore support mechanisms like Contracts for Differences (CfDs) or allocating Financial Transmission Rights (FTRs) have been suggested for the fair redistribution of socio-economic welfare and promoting investment in offshore wind energy (TenneT, 2020) (Thema, 2020).
The target set by the European Union necessitates substantial investment in offshore wind energy, particularly in the North Sea. The OWFs are being developed as hybrid projects and the separate markets for offshore energy are being developed called OBZs. However, the introduction of OBZs introduces significant price and volume risks deterring investment by making the revenue to the OWF owners unpredictable. While Contracts for Differences (CfDs) are being proposed as a tool to mitigate these risks, the existing literature does not quantitatively answer how the CfDs can be optimised to be effective in an offshore environment, nor does it explore the long-term impact on investment behaviour.

1.3 Gaps in Literature

Congestion income:

The implementation of OBZ leads to a more efficient dispatch, however, the distribution of the revenue gets affected. Due to the large amount of cross-zonal flow, significant congestion revenue is gained by the interconnectors, which, in this case, is the TSO (NSWPH, 2021).
The revenues obtained by the investors cannot be distributed to other parties involved in the project to recover their costs. Article 19 of EU regulation 2019/943 mandates the congestion revenue to be allocated for expanding or securing the cross-zonal capacity (European Union, 2019). Additionally, if

the requirement for tending to the cross-zonal capacity is met, the revenue should be redirected to the network users by reducing the tariffs. The restrictions prevent the transmission owners from being able to reallocate the congestion income to the wind farm investors. It is suggested that a redistribution approach can applied to avoid the regulations laid by Article 19 and ensure that investors get some of the congestion revenue (Thema, 2020).

Price and Volume risks:

The expansion of offshore wind capacity leads to the cannibalism effect (Kitzing et al., 2024b). As the share of a particular technology grows, the capture price of the energy produced by the technology decreases during periods of high output. This cannibalism effect is observed to a large extent in offshore bidding zones, where wind energy dominates. This exposes the investors in offshore wind to the inherent price risk of offshore wind. The price in the OBZ depends on the entire grid of the CCR and not just the adjacent bidding zones. FBMC will calculate the price in the OBZ considering the volume of wind produced and the export required. In case the wind produces loads up the critical network elements of the highest-priced zone, the price in the OBZ has to be lowered to reach an optimal welfare solution (Thema, 2020). This makes the projection of the prices in an OBZ very difficult to predict in the long term. The prices are largely influenced by neighbouring markets and transmission congestion, which exposes the generators to price risks.

Volume risks arise from technical constraints, intrinsic variability of wind resources and from market competition. Forecast errors in wind output reduce revenue certainty, while negative price periods in neighbouring zones can displace OBZ exports in favour of cheaper imports, as highlighted by (Elia, 2023). These structural risks reduce the bankability of offshore wind investments unless addressed by policy instruments such as CfDs.

CfDs are often proposed to mitigate price and volume risk. However, existing literature does not sufficiently explore how CfD design itself can avoid creating new market distortions, particularly in dispatch behaviour and bidding incentives. This thesis addresses that gap by analysing how different CfD structures mitigate risk but cause unintended operational efficiencies. Specifically, it explores how CfD schemes can be designed to reduce exposure to price and volume risk, the resulting dispatch distortions. Finally, it shows how these design choices influence investment and technology selection in OBZs.

Investment behaviour:

According to (NSWPH, 2022) clarity on the market setup early on in the project is essential for the investment in offshore wind farms by project developers. Especially, based on the previous research gaps identified, since there are unaddressed risks, investment in hybrid projects depends on the policy framework. There is a lack of studies on the investment in generation assets after the impact of the various price signals from different market setups (Kenis et al., 2024). Denmark has approved the creation of DK3, an OBZ linked to the Bornholm Energy Island, to manage structural congestion between Bornholm and mainland zones. Although not yet active, DK3 is expected to come into effect by 2030 and aims to facilitate the efficient integration of offshore wind into the market (Energinet & Agency, 2023). Therefore, there is little evidence of the long-term implications of investment in a hybrid project in an offshore environment. The lack of regulatory certainty introduces significant risk to the investors making them more risk-averse. Investing in offshore wind involves significant capital expenditure, and due to the low marginal costs associated with wind energy production, generators of wind farms focus on achieving a positive cash flow (Dedecca, Hakvoort, & Ortt, 2016). However, as discussed earlier, under an OBZ system this assumption is more precarious due to the occurrence of price collapse hours (Kenis et al., 2023). While the literature mentions the importance of support framework like CfDs, the technological biases resulting from a particular design are not discussed. The absence of an established OBZ setup creates a gap in understanding the long-term implications of investment in these projects. The lack of historical data on such an investment in a novel market setup exposes the investments to risks. Therefore, it is crucial to investigate investment decisions for offshore hybrid projects within a model that accurately represents the offshore environment under an OBZ setup. Furthermore, research should explore how barriers to investment can be mitigated through the implementation of CfDs (Orsted, 2020).

1.4 Research questions

The gaps in the literature as substantiated earlier indicate that there is a need for policy intervention to mitigate the risks faced by OWFs in OBZs. CfDs are widely recommended in literature as a means to mitigate some of the risks faced by offshore wind generators. The research question is framed so that the prominent CfD schemes are studied in the context of an offshore environment.

How can Contracts for Difference (CfD) schemes be designed and implemented in offshore bidding zones to incentivise investment in offshore wind farms, and how do they influence operational behaviour and technology preferences?

This research question states the importance of support policies, specifically CfD for long-term risk mitigation. Offshore Bidding Zones are exposed to price and volume risks. Due to the high concentration of wind turbines in these bidding zones, the revenues made by the generators are more uncertain than onshore wind turbines. This demonstrates the need for hedging against the uncertainty risks, prompting the need for CfD.
The prominent CfD instruments being discussed are enumerated and their relevance in a European offshore environment is established. Using Flow-Based Market Coupling (FBMC) and Advanced Hybrid Coupling (AHC), the market clearing is devised for a representative offshore bidding zone. The challenges associated with the CfD schemes are quantified in the model, and the measures to mitigate them are devised. Additionally, the impact of the CfD implementation on the investment patterns in offshore wind turbine technology is studied.

Subquestions framed to answer the primary research question are:

- *What are the different types of CfDs being studied and their relevance in the context of an offshore market?*

  The first subquestion is used to establish a typology of CfDs and why they are relevant in OBZs. It also aims to understand some of the risks in the OBZs that prompt a need for CfD intervention. This question is answered through literature by going through some of the prominent CfD types in recent times and categorising them into production-based and non-production-based CfDs.

- *What are some of the challenges faced by the existing CfD schemes that are not captured in the current analysis, and how can they be quantified effectively?*

  The following question aims to substantiate the risks effectively mitigated by the CfDs. However, it also explores the structural shortcomings of existing CfD models. Their tendency to mute price signals, misalign incentives or expose generators to volume and basis risk is explored partly through a mathematical model and partly through existing literature. These challenges are often described qualitatively in policy discussions but lack systematic quantification. To address this, the thesis introduces a set of operational and financial metrics that can numerically capture the effects of CfDs under different system conditions.

- *What are some of the operational inefficiencies triggered by the implementation of the aforementioned CfDs in an offshore environment, and how can they be quantified?*

This question aims to investigate how certain CfD designs may distort day-ahead bidding behaviour and dispatch decisions in offshore wind farms. For example, hourly production-based CfDs may incentivise overproduction during low-price or even negative-price periods. These inefficiencies are quantified through simulation outputs. They include generation during curtailment, exports during low-value hours, and utilisation of grid infrastructure. The model allows for direct comparison of these inefficiencies across CfD types and scenarios, shedding light on design features that enhance or hinder market efficiency.

- *How does the implementation of a particular CfD measure influence a certain technology choice?* The final question examines whether the design of a CfD scheme implicitly favours certain offshore wind turbine technology over others. Technologies with different power curves and rated capacities respond differently to wind conditions. The aim is to see if the more advanced non-production-based CfDs reward stable revenues or high-volume generation, which can unintentionally bias investment decisions. OWF's performance is studied across multiple CfD types to explore how CfD designs shape technology selection and whether they encourage system-friendly designs or skewed investment patterns.

1.5 Research Methodology

This research project aims to demonstrate how using CfDs can mitigate some of the risks faced by offshore wind generators. The project aims to provide insight into the application of a CfD framework within a representative OBZ. This is done by means of quantitative desk research and a literature review into some of the gaps in the current literature prompting the introduction of CfDs in OBZs. This is followed by a deep dive into the various prominent CfD designs in literature and the CfD designs being implemented in the world. Most research points towards capability-based, financial and yardstick CfDs being effective due to being independent of generation as stated by (Kitzing et al., 2024b). Hence, specific attention is paid to these CfD mechanisms, which helps answer the first research question. Following this, the mitigation of some of the risks that being in an OBZ exposes the generators to, are discussed. The last part of the qualitative analysis is the indication of some of the challenges which may be triggered in the day-ahead market after the implementation of the discussed CfD measures.

After answering the first two research questions, the next step involves implementing the proposed CfD tools discussed earlier, in an OBZ model to evaluate its performance and demonstrate some of the challenges experienced. To determine the effects of the CfD on the offshore market, a mathematical model is made on Julia, and the price is formed by FBMC and AHC.
This thesis builds on the flow-based market coupling model developed by (Kenis et al., 2023), available through the GitHub repository (Kenis & Bruninx, 2024). The same grid topology is directly adopted for this study. The model is extended by introducing a wind farm decision block, which simulates the operational response of offshore wind farms under different CfD schemes.

The model is designed to study the prominent CfD designs and how they perform in the long run. Two key scenarios are studied: one with a standard OBZ setup and another incorporating CfD mechanisms. The model evaluates the extent to which the discussion about the implementation of CfDs holds. This provides a clear understanding of the pricing structure and the risk reduction offered by a CfD instrument. The projected capacity of offshore wind energy and the future energy mix according to the targets set by the government is run in the model to examine the performance of the CfD in an environment with a large share of offshore wind in the mix. This will aid in assessing if the CfD instrument supports and to what extent does it incentivise long-term investment. Furthermore, the model aims at identifying the operational inefficiencies triggered by the CfD design when implemented in a day-ahead market. The root cause of these inefficiencies is identified and mitigated, thereby designing an optimal CfD for an offshore environment.

In addition, the various offshore wind turbine technologies are studied and the model is used to examine whether the implementation of the CfD design introduces any biases in the investment behaviour. This includes studying is the recommended CfD instrument might favour specific turbine technology over others, potentially distorting the investment landscape.

2 | Theoretical Background

This chapter discusses the market design for the deployment of offshore wind energy in Europe. The first section focuses on an overview on the European electricity market, focusing on the structure and operation of the day-ahead market. The following chapter explores the flow-based market coupling (FBMC) mechanism. This section is the basis for the model for the offshore bidding zone.

2.1 The European Electricity Market

The European power market is structured with a multitude of actors, including generators, consumers, distributors, and facilitators. The generators decide the production costs of the electricity they produce, and based on the willingness to buy of the consumers, the price of a unit of electricity is decided. The consumers and the producers bid a day in advance, the respective amount of energy required and produced. The Day-Ahead (DA) Market is where the bids for production and consumption are met.

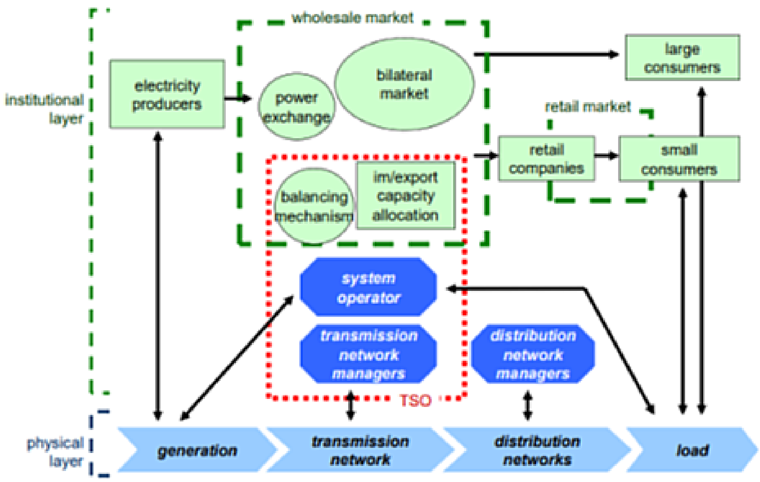


Figure 2.1: Electricity market layers and actors
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This report will only focus on the DA market and its implications on Offshore Wind.
The DA market functions on the bids submitted by the spot market actors. The system operator conducts market clearing by matching bids with orders from the producers, ultimately determining the market-clearing price. The consumption, production levels and energy prices are determined through an optimisation process that maximises social welfare (Aghaei, Shayanfar, & Amjady, 2009).

The different zonal markets are interconnected, which proves to be an economically efficient design. However, there is a disconnect between the physical and the commercial flow arising due to the point-to-point nature of the commercial flow and the physical power flow following Kirchhoff's laws. The wholesale price for an entire zone can not represent limitations of the physical power flow in the grid. Therefore, accurate calculation of capacity limits is vital for an efficient power flow, without which there could be an overloading of the transmission lines, leading to congestion. The Transmission System Operators (TSOs) are required to calculate the cross-border capacity, which is done by building a model of the hourly inputs from generation, load and the network status. The cross-border capacity input is vital to the tallying of bids to ensure power flows efficiently. Providing interzonal trading increases societal welfare. However, the physical limitations on the amount of tradable power make the capacity calculation an important process in the market-clearing process. The correct representation of accurate trading capacities for market clearing by the TSOs is important to aid the grid congestion management (Schönheit et al., 2021).

There exist two methods for cross-border capacity allocation, namely Available Transfer Capacity (ATC) and Flow-Based Market Coupling (FBMC). Historically, ATC was used for capacity allocation and it involves a simplification of the physical characteristics of the grid, therefore leads to inaccuracies. ATC does not fully consider the real-time grid conditions or the network conditions, leading to suboptimal capacity allocation. Therefore, FBMC has been used for capacity calculation in the Central Western European (CWE) region since 2015. FBMC gives a more authentic approach to the real-time physical grid utilisation by including physical line restrictions for both cross-border and intra-zonal lines.

2.2 Flow Based Market Coupling

The commercial transactions are translated into physical flows, and the physical limitations are translated into commercial transactions. The nodal Power Transfer Distribution Factors (PTDF) are used, which contain the linear relationship between the nodal injections in the grid and flows through the line. Nodal PTDFs are calculated from a DC power flow analysis of the electricity grid.

TSO determine a set of parameters ex ante to estimate the flow in critical elements using zonal PTDFs and estimate the commercial transmission capacity that can be traded in the day-ahead market. (limits on the estimated flows Remaining Available Margin (RAM))
The FBMC model in literature is determined in three steps, as noted in figure. The base case, or D-2, is utilised to ascertain the flow-based parameters, and the state of the grid can be evaluated on the day of delivery. From the D-2 case information, an optimisation model is employed to calculate the flow in the lines, which corresponds to the day-ahead market clearing step. The constraints within the grid are represented using the parameters established in the base case. While the limitations imposed during the day-ahead market clearing can yield an accurate output, real-time congestion may occur due to various factors, necessitating intervention for resolution. Consequently, the redispatch step is carried out by the TSOs to ensure flow respects physical limits.

The flow based market coupling monitors the physical limitations of the grid network and anticipates how the market changes affect the electrical flows on these elements (Pereira, Tavana, Di Caprio, & Govindan, 2021).

2.2.1 Flow based parameters

The flow-based market coupling relies heavily on the key predictive parameters like the Generation Shift Keys (GSKs) and the prediction of the congestion in the network elements. GSKs try to anticipate which power plants offset trade balance changes of the involved zones and enable the change from market information to grid utilisation. The parameters defined are crucial to understanding the shape and size of the trading domain, which in turn determines the amount of trade carried out between zones. If the parameters are not defined correctly, it can result in overconstrained domains, leading to a suboptimal outcome where price convergence is not achieved. On the other hand, with an oversized domain, there will be a greater volume of power traded compared to what is possible, leading to corrective action and high congestion costs. Therefore, accurate estimation of the flow parameters is important.

The power flow model is linearised and used in techno-economic applications called DC load flow (DCLF). Since the model is linear, it is used to accurately determine the dispatch decisions using the line subject to the thermal constraints. The DCLF matrix, which shows the relation between the nodal injection and the line flows, forms the Power Transfer Distribution Factors (PTDF) (Schönheit et al., 2021). The linear power flows are considered here, which means that only the active power is considered, while the reactive power is not included in this model. The major factor in determining the line constraints is the active power therefore, only that component is considered. Managing reactive power is crucial for balancing the voltage level in the grid, but it does not contribute to the market-optimal energy exchanges.

Market coupling performed a day ahead can lead to deviations from the base case predictions, which is denoted by the change in position. The GSKs capture how this change in position is distributed among the generating units of the zone. The GSKs assign weight to nodes according to the response of generation units attached to the nodes on the change of net position. The GSKs provide information on which plants within a node will contribute to a change in position and quantify, with a ratio, what the predicted contribution will be. They are denoted as $GSK_(n, z)$ for having information on the net position change of each zone and its contribution from each node. The GSKs enable the transformation of the nodal $nPTDF$ matrix to a zonal $zPTDF$ matrix. In addition to the nodal injection and line sensitivities, the GSKs enable one to see how a net position change affects flows on the lines. This helps to capture the changes in flow based on zonal position changes, enabling the model to account for physical constraints while clearing the market on a zonal basis.

$$\text{zPTDF} = \text{nPTDF} \cdot \text{GSK} \tag{2.1}$$

In FBMC, Critical Network Elements are considered in market clearing because they are deemed to have an impact on market clearing. The flow changes are captured using the parameters discussed above. The $nPTDF$ matrix captures the impact of nodal injections to lines, the GSKs capture the ratio split of generation based on position changes and the net position change. Together, these variables capture the change in flow on the CNEs in the DA market.

The next important parameter for FBMC is the Remaining Available Margin (RAM). They are computed as parameters that set the upper and lower bound for the flow changes in the CNEs. They aim to solve the mismatch between the commercial flows as an outcome of the market clearing and the physical limitations of the grid. This means that the difference between the commercial flows and the physical flows should be within the thermal limits of the CNEs. The positive difference is represented by RAM^+ and the negative difference is represented by RAM^+. In other words, the RAM constraint ensures the maximum power that flows through the CNEs does not violate its thermal limits. Security margins are defined for the CNEs in the form of Final Adjustment Value (FAV) and Final Reliability Margin (FRM) which is subtracted from the RAM values when it is a positive limit and added when it is a negative limit. This gives leeway to account for any conditions not being accounted for in the FBMC process to ensure that the physical limitations of the grid are not violated.

A minRAM constraint is being applied by TSOs, which should ensure that 70% of the capacity on an interconnecting must be reserved for cross-border interconnection during market coupling.
NTC is a parameter used to limit the capacities of the DC line

2.2.2 Flow based domain

The base case D-2 step of the market clearing is used to establish the flow-based (FB) domain. This flow-based domain is an essential step in calculating the DA market output based on the predictions made D-2. The FB domain represents the set of constraints and acceptable grid limits within which the net positions of the zones should lie. The flow-based parameters PTDF and RAM are derived to calculate the sensitivity of grid flows to changes in the net position of the zones, while the PTDF matrices calculate the available transmission capacity on the CNEs. These parameters are calculated to ensure the grid operates within its thermal and operational limits, taking into account contingencies such as line outages or generator failures. The flow-based domain thus establishes the feasible set of net positions for the zones, ensuring that any market outcome within this domain adheres to the physical limitations of the transmission network. This domain is crucial in market clearing, ensuring the reliable operation of the electricity system.

The constraints defined in the D-2 base case step act as the boundaries for the solution space of the D-1 market clearing. The change in the flow on the CNE l with the zonal net position p_z is represented by the equation below (Li & Seguinot, 2017).

$$\Delta F_l = \sum_{z \in \mathcal{Z}} zPTDF_l^z \cdot p_z \tag{2.2}$$

$$\Delta F_l \leq RAM_l \tag{2.3}$$

RAM restricts the change in flow ΔF_l for each line l. It sets the upper (RAM_l^+) and lower bound (RAM_l^-) for the position change on the AC line l. This is represented in the equation below.

$$RAM_l^- \leq \sum_{z \in \mathcal{Z}} zPTDF_l^z \cdot p_z \leq RAM_l^+ \tag{2.4}$$

$$\sum_{h \in \mathcal{H}} NTC_h^- + \sum_{l \in \mathcal{L}} RAM_l^- \leq p_z \leq \sum_{h \in \mathcal{H}} NTC_h^+ + \sum_{l \in \mathcal{L}} RAM_l^+ \tag{2.5}$$

This sets the boundaries, which are considered as the Flow-based Domain. The dimension of the solution space depends on the number of zones in consideration. For considering the power flow on the cross-border lines, which can be AC or DC, NTC needs to be added to the equation.
Therefore, equation 2.4 can be extended to add NTC_l^- and NTC_l^+ as the upper and lower bounds, respectively.

2.2.3 Advanced Hybrid Coupling

Advanced Hybrid Coupling (AHC) has not yet been implemented in the Core CCR. Currently, HVDC interconnectors and external AC borders in the FBMC process are modelled using Standart Hybrid Coupling (SHC). While AHC is designed to capture the interaction between HVDC and AC lines by integrating the flows on both in the flow-based domain. According to (*Second Amendment of the Day-Ahead Capacity Calculation Methodology of the Core Capacity Calculation Region*, 2023), AHC is required to be implemented on technically feasible and beneficial external HVDC borders of the Core CCR, with the exception of Italy North CCR and SWE CCR.

Advanced Hybrid Coupling (AHC) is an enhancement to Europe's flow-based market coupling mechanism, introduced within the Single Day-Ahead Coupling framework to better coordinate cross-border capacity allocation by fully accounting for the influence of exchanges from adjacent CCRs (ENTSO-E, 2023). Under the previous standard hybrid coupling approach, interconnections between a flow-based region and its neighbours were handled through fixed net transfer capacity (NTC) limits, effectively reserving a portion of internal grid capacity for external trades (ENTSO-E, 2023). This meant that the use of those critical network elements by cross-border flows was not available to trades between flow-based zones (Schlecht, Maurer, & Hirth, 2024), often leading to inefficiencies such as unscheduled allocated flows on the network (i.e. unaccounted loop flows resulting from exchanges on borders of adjacent CCRs) (ACER, 2023). AHC addresses this limitation by integrating external exchanges directly into the FBMC optimisation through virtual bidding zones (Schlecht et al., 2024). Flows on interconnectors to non-flow-based areas must compete on equal footing with internal flows for Available Transmission Capacity, ensuring a more transparent and non-discriminatory allocation of cross-zonal capacity (ENTSO-E, 2023). This advanced coupling ultimately enhances the coordination of cross-border exchanges across regions, reducing unplanned loop flows and improving the efficiency of capacity usage, and is expected to increase overall socio-economic welfare in the European day-ahead market (ENTSO-E, 2023).

2.3 Link to OBZs

The principles behind AHC are directly applicable to the emerging integration of OBZs, especially those associated with large-scale OWFs. OBZs are often implemented as injection-only bidding zones. They often have no local demand and are fully dependent on cross-zonal transmission capacity. This setup inherently resembles the external border dynamics that AHC is designed to handle. Like non-Core CCR exchanges, OBZs compete with internal flow-based trades for scarce capacity on CNEs. Thus, OBZs would benefit from an AHC framework that enables offshore injections to be integrated into the flow-based market coupling optimisation, rather than treated via fixed NTC reservations or simplified coupling approximations.
The operational and economic dispatch decisions of OWFs located in OBZs are strongly influenced by the underlying market coupling algorithm. In traditional SHC or NTC-based frameworks, OWFs may face inefficient curtailment or volatile price signals due to arbitrary capacity reservations or poorly modelled congestion interactions. Integrating such offshore assets into the FBMC with AHC would allow their output to compete more efficiently with onshore generators, ensuring better utilisation of transmission infrastructure.

2.4 Conculsion

This chapter provided an overview of the European electricity market structure with a focus on the day-ahead market and the mechanisms governing cross-zonal electricity trading. The limitations of traditional ATC-based capacity allocation were discussed, highlighting the benefits of FBMC in accurately representing physical grid constraints through parameters such as PTDF, GSK, and RAM. The concept of the flow-based domain was introduced, showing how market positions are constrained to ensure secure grid operation.

The chapter then examined AHC as a refinement of existing coupling mechanisms, aimed at better integrating exchanges across bidding zones and capturing the interaction between HVDC and AC flows. AHC is shown to enhance efficiency in capacity allocation, especially on the external borders of the Core CCR.
Finally, the relevance of AHC to OBZs was outlined, particularly in the context of OWFs. OBZs' effective integration into the market depends on accurate modelling of their interaction with the grid.

3 | Contracts for Difference

This chapter begins by examining the role of CfDs in enabling offshore hybrid projects, highlighting the rationale behind their use. It then discusses the key risks that CfDs are designed to mitigate. Various CfD schemes proposed in the literature are reviewed, with a focus on their design features and underlying principles. The chapter also considers the potential distortions and inefficiencies that may arise from implementing these schemes, particularly in how they influence the decision-making of OWF operators. Finally, a set of performance metrics is introduced to evaluate and compare the effectiveness of the CfD schemes covered.

3.1 Need for CfDs

Introducing OBZs is efficient for an optimal market outcome, however, they expose the wind farm operators to different risks, which, if unmitigated, can lead to disincentivisation in investing in offshore wind.

The North Sea is at the heart of Europe's offshore wind expansion, with ambitious capacity targets aligned to EU climate goals. However, recent market turbulence from supply chain cost inflation to volatile electricity prices has exposed a mismatch between risk and reward in offshore wind development. In Denmark's 2025 North Sea tender, for example, no bids were submitted for 3 GW of offshore wind; developers cited sharply rising costs alongside "low and uncertain earnings opportunities" under a subsidy-free design (Memija, 2025). This outcome has prompted a rethink of auction models and highlighted the need for long-term revenue stabilisation mechanisms. In this context, CfDs have emerged as a crucial policy tool. CfDs are long-term contracts that pay (or charge) the difference between a fixed "strike" price and the volatile market price, thereby shielding investors from wholesale price fluctuations. CfDs are needed in North Sea offshore wind bidding zones to mitigate revenue risk, incentivise investment, stabilise market signals, and align with EU energy policy objectives.

Offshore wind projects are very capital-intensive projects, with as much as 80–90% of lifetime costs incurred upfront during construction (Haering, 2023). Once built, they face near-zero marginal costs and rely on selling electricity into inherently volatile markets. The revenues of the wind farm developers depend entirely on market prices. This creates a heightened exposure to market price risk for offshore wind, which can seriously threaten the economic viability of projects (Haering, 2023). Existing power markets offer only limited long-term hedging options, so stable long-term contracts are often necessary for renewables financing (Beiter, Guillet, Jansen, Wilson, & Kitzing, 2023). Contracts for Differences have been suggested as a solution for solving some of these issues faced by the OWF operators. In effect, CfDs aim to reduce price volatility risk for the developer (Beiter et al., 2023). The developers seek this revenue stabilisation in order to cover capital costs and provide returns.

Crucially, CfDs mitigate revenue risk without necessarily constituting a permanent subsidy. A common misconception is that CfDs are mere handouts for uneconomic projects, but research suggests their primary role is risk management rather than a subsidy (Beiter et al., 2023). Even if expected power revenues over a project's life equal or exceed the cost, developers and lenders often demand a CfD to guard against downside price risk. This insight reframes CfDs as insurance-like instruments.

Rather than simply propping up uneconomic ventures, a well-designed CfD provides revenue certainty that unlocks financing for projects that would otherwise stall due to risk aversion. Empirically, over 50% of global offshore wind capacity has been procured under CfD-type arrangements, underscoring their central role in the sector (Beiter et al., 2023)(Haering, 2023).
By reducing exposure to price volatility, CfDs lower the risk premium demanded by investors, which in turn reduces the cost of capital. Studies have quantified this effect: the introduction of long-term CfDs in the UK, for example, helped drive down the weighted-average cost of capital (WACC) for offshore wind projects, contributing to substantial declines in strike prices over the past decade (D. Newbery, 2021). By hedging price risk, CfDs give developers the confidence to invest and enable projects to be financed at significantly lower rates, a benefit ultimately passed on to electricity consumers through cheaper power (Regulatory Assistance Project, 2023).

The stabilisation of revenue streams via CfDs strongly incentivises investment by improving the risk-reward balance for offshore wind developers. With most project risk concentrated in the upfront expenditure, investors require assurance that future revenues will cover debt repayment and yield a return. CfDs directly address this by removing the worst-case scenario of sustained low market prices. This risk reduction catalyses investment at scale, a fact reflected in Europe's offshore wind boom wherever robust support schemes exist (D. Newbery, 2021).
Beyond individual projects, CfDs contribute to long-term market creation and scaling of the offshore wind industry. Stable long-term contracts send a reliable market signal that there will be a steady pipeline of projects with acceptable risk-adjusted returns (Memija, 2025).
Indeed, meeting the EU's offshore wind objectives of 60 GW by 2030 and well over 200 GW by 2050, will require mobilising vast investment in the North Sea region. Policymakers recognise that this is only feasible if revenue risk is contained. The European Commission's recent market reform proposals explicitly encourage Member States to use long-term contracts. The Commission notes that a rapid expansion of corporate PPAs and CfD is key to making clean energy production more attractive to investors and to delivering end-user affordable prices. The typical contract length for PPAs for offshore wind is 10-15 years (Dukan, Gumber, Egli, & Steffen, 2023), which is typically shorter than the lifetime of the turbine (20-30 years). This, therefore, does not effectively cover the risks faced by OWFs. Thus, CfDs are increasingly seen not as an aberration or temporary subsidy, but as a structural feature of a decarbonised power market that can efficiently channel capital into new renewable capacity (Haering, 2023).

3.2 Risks in OBZs

Offshore wind farm developers face various risks intrinsic to renewable energy investments, providing essential financial security for producers:

3.2.1 Price risks

Offshore hybrid projects are exposed to several forms of price risk that can significantly affect their revenue certainty and investment attractiveness. These risks are especially relevant in OBZs, where price formation mechanisms diverge from those used in onshore markets.
One of the most fundamental risks is the *flat price risk*, which stems from general uncertainty in future wholesale electricity prices. This risk is inherent to all generators, regardless of location, and reflects broader market volatility over time (North Sea Wind Power Hub Consortium, 2023).

More critical in the OBZ context is the *locational basis price risk*, which arises from the potential misalignment between prices in the offshore zone and the neighbouring onshore bidding zones. This difference complicates the establishment of contracts such as PPAs between offshore generators and onshore consumers, as it introduces uncertainty in expected revenues. The offshore price can vary structurally from the onshore price due to market design. For project developers, this implies a risk that the offshore price may consistently underperform relative to expectations set by the onshore market (North Sea Wind Power Hub Consortium, 2023).

The *price collapse risk* occurs when the offshore zone is unable to export electricity to neighbouring bidding zones due to limited transmission capacity. Such constraints can arise from reduced capacity in HVDC interconnectors or from limitations within the onshore grid. For instance, if the OBZ is coupled to several onshore zones but is given insufficient cross-border transmission capacity, the offshore price may collapse to its marginal price. These restrictions limit the amount of electricity that can leave the offshore zone, resulting in a local oversupply and a decline in market prices. During these periods, offshore generators may receive no revenue if they are not supported by a government mechanism. Developers have raised concerns about this risk because it affects the financial viability of offshore wind projects. The likelihood and severity of price collapse risk remain uncertain, making it essential to investigate the issue in greater depth.

Non-intuitive price risk occurs when the OBZ price falls outside the expected range defined by adjacent bidding zone prices. This can happen when market exchanges from the OBZ, whether from offshore wind generation or import/export activity, place disproportionate stress on critical network elements within capacity calculation regions (CCRs). In such cases, the OBZ price may be lowered to incentivise system-optimal dispatch. Conversely, when the OBZ alleviates congestion, the price may increase. This effect, driven by advanced hybrid coupling (AHC), cannot be predicted by simple economic logic and introduces further revenue uncertainty for developers (Elia & Orsted, 2024).

3.2.2 Volume risk

The primary form of volume risk for OWFs is in the form of *weather risk*, stemming from the inherent variability and uncertainty of wind resources. Offshore wind is entirely dependent on meteorological conditions, which can deviate from long-term averages. Wind output in Northern Europe can vary by as much as 20 % year on year (Staffell & Pfenninger, 2018). This highlights the challenge in forecasting and planning around the variability, which in turn affects the long-term revenue predictability and daily operations. In the OBZ context, weather risk is compounded by structural constraints, as excess wind energy leads to large-scale curtailment while low wind periods mean revenue shortfalls.
Volume risk refers to the uncertainty around the actual amount of electricity traded compared to what was anticipated, regardless of price. In offshore hybrid projects, several forms of volume risk can arise depending on how the OBZ is configured, connected, and integrated into the wider market.

One important source of volume risk stems from technical unavailability, such as the delayed commissioning or malfunctioning of HVDC links that connect offshore generation to onshore grids. When such infrastructure is not available as planned, offshore generation cannot reach the market, leading to curtailed volumes and lost revenue. This is referred to as the *technical unavailability volume risk* (TenneT, 2024) .

A second type of volume risk arises when the total installed generation capacity in the OBZ exceeds the available export capacity of the interconnectors. In such cases, even when all generation assets are operational, physical constraints limit the amount of power that can be exported to the onshore grid. This leads to a supply-demand mismatch in the OBZ, influencing price formation and revenue certainty. If the export constraint is binding, market outcomes may favour generators that are better positioned to access the interconnectors. This type of imbalance is especially relevant for projects relying on hydrogen production or power-to-X applications. It is referred to as the *local demand volume risk* (TenneT, 2024).

A third volume risk is linked to the allocation of interconnector capacity in the market coupling framework. When offshore wind farms share interconnector capacity with other market participants, the volume available for offshore generators depends on the allocation rules used by the market algorithm. In flow-based market coupling (FBMC), this allocation depends on the impact of flows on critical network elements and may not always prioritise offshore exports. If offshore wind flows are deemed to worsen congestion in key parts of the grid, their access to interconnector capacity may be reduced, even if physical capacity exists. This situation introduces the cross-border *capacity allocation* volume risk (Elia & Orsted, 2024).

Lastly, volume risk can also result from the capacity calculation stage of the FBMC process. During this stage, TSOs identify CNEs, including hybrid offshore links, and calculate a RAM using conservative estimates to ensure grid reliability. Although the physical infrastructure may support higher export volumes, TSOs withhold capacity to account for forecast uncertainty, typically during the D-2 stage of the process. As a result, the capacity allocated to the OBZ may be reduced even when no actual technical constraints exist. For example, an offshore wind farm with 1000 MW of export capacity might be limited to only 800 MW in the market due to a conservative RAM. This discrepancy between technically available capacity and market–allowed capacity is known as *capacity calculation volume risk* (Elia & Orsted, 2024) (Verkooijen, 2024).

3.2.3 Impact of risks on OWFs

The price and volume risks mentioned above, which are a structural consequence of the FBMC process. In addition to these risks, specifically for OWFs there is considerable price cannibalisation in OBZs. There is a high wind buildout in the North Sea and Europe, where the marginal price of wind is close to zero and periods of high wind cause a large influx of power in the grid, suppressing wholesale electricity prices. This effect is more pronounced in OBZs.

Moreover, there are technical limitations imposed by the interconnector infrastructure. The flows between zones are constrained by thermal limits and grid security considerations. Therefore, the OWFs in OBZs are entirely dependent on the available interconnector capacity for market access. Most OBZs lack local demand, unless a flexible agent such as an electrolyser or battery is installed.

All of these factors together create a high-risk environment for OWF developers. These conditions compromise revenue certainty and increase investor risk. Therefore, policy intervention is necessary to instil confidence in investors.

3.3 CfD Design Typologies

The large wind build-out in OBZs leads to large capacities of wind, which have zero marginal costs. The large amount of wind feed in at times of high wind potential leads to an effect called the Cannibalisation Effect. This leads to a reduction in the value of the wind energy output. The OBZ leads to an uncertainty in the revenue profile for wind farm developers, requiring the need for support from the government to stabilise the revenues. An important function of the CfD is to cap the revenue off at times of high prices for the generators. The effectiveness of this depends on the design of the CfD policy.

Contracts-for-Difference (CfDs) are financial instruments widely utilised within electricity markets to stabilise revenues for renewable energy (RE) producers. They effectively address fluctuations between actual market prices and predetermined strike prices, thereby enhancing investment attractiveness and supporting broader environmental policy goals. The CfD mechanism operates on the principle of a fixed strike price, typically determined through competitive auctions or administrative benchmarks, which is compared against a fluctuating market reference price. If the prevailing market price is below the strike price, producers receive a payment from the government, covering the shortfall. Conversely, producers repay any surplus to the government if market prices exceed the strike price, a mechanism known as clawback.

CfDs have gained prominence, particularly in Europe, due to their dual ability to protect producers from market volatility and safeguard consumers against high electricity costs by redistributing excess revenues. The design flexibility of CfDs allows adaptation to specific market conditions and policy objectives, making them versatile instruments to support renewable energy expansion and economic stability within the energy sector.

3.3.1 Production-based CfDs

Overview

Production-based Contracts-for-Difference (CfDs), also known as generation-based CfDs, constitute the most widely implemented category of CfD design across Europe. These instruments provide financial support by directly linking compensation to the actual electricity output of a renewable energy generator. Producers receive payments when the reference market price—most commonly the day-ahead market price—falls below a predetermined strike price. Conversely, if market prices exceed the strike price, producers are required to return the difference to the government through a clawback mechanism. This symmetrical arrangement ensures a stabilised revenue stream, enhancing investment security for capital-intensive renewable energy technologies (Kitzing et al., 2024a) (ENTSO-E, 2024b).

Design dimensions

Reference periods

A critical design variable within production-based CfDs is the reference period used for calculating the settlement amount. Hourly CfDs provide revenue certainty by calculating support payments based on hourly market fluctuations. While this significantly de-risks projects and facilitates financing, it may also create perverse incentives, encouraging continuous production even when market prices turn negative. This behaviour can contribute to grid congestion, imbalance costs, and inefficient market outcomes. To mitigate such inefficiencies, some schemes suspend CfD payouts during periods of negative prices or impose caps on total payouts (Kitzing et al., 2024a).

By contrast, longer reference periods such as monthly, quarterly or annual. They introduce a degree of price exposure, thereby promoting a stronger alignment between operational behaviour and broader market trends. These designs encourage producers to optimise generation following prevailing market signals, improving market integration. However, this also increases basis risk, as the actual generation profile of a plant may diverge from the average price used for reference. Thus, the choice of reference period has important implications for both risk allocation and market efficiency (Kitzing et al., 2024a).

Reference price methods

The method used to determine the reference price introduces further differentiation:
Technology-specific referencing involves calculating support payments based on a particular technology class, such as solar PV, onshore or offshore wind. This method minimises basis risk by aligning compensation with the production potential of the specific technology. It is especially well-suited for emerging technologies that require tailored support during their scale-up phase. Nonetheless, such an approach may inadvertently limit cross-technology optimisation and reduce incentives for system-wide efficiency improvements (Kitzing et al., 2024a) (ENTSO-E, 2024b).

Technology-uniform referencing, by contrast, aggregates reference prices across multiple renewable technologies. While this supports technological neutrality and competition, it exposes producers to a higher degree of basis risk. For instance, wind and solar generators have different temporal production profiles, meaning a uniform reference price may not reflect the actual value of energy generated by a specific technology. Producers operating under this model are incentivised to pursue flexible strategies, such as co-location with storage, to reduce revenue variability and increase responsiveness to system needs (Kitzing et al., 2024a).

Flat average market price referencing, often based on baseload prices, offers administrative simplicity and transparency. However, it introduces the greatest risk exposure. Because renewable generators often earn below-average market prices, due to the timing of their output during low-demand periods, this approach may render projects less bankable unless strike prices are sufficiently elevated to compensate for the risk. While it strongly promotes market-aligned behaviour and operational innovation, it may deter investment in newer technologies that are more sensitive to revenue certainty (Kitzing et al., 2024a).

Producers under this scheme face greater uncertainty and must carefully manage operational strategies to maximise revenues. This heightened risk profile pushes producers to develop advanced forecasting and operational management capabilities, potentially driving technological and managerial innovation within the renewable energy sector.

Subtypes

Two-sided CfDs

Two-sided CfDs are the most commonly adopted form of support in European electricity markets. They involve symmetrical settlement: when the reference market price falls below the strike price, the state pays the producer the difference; when the market price exceeds the strike price, the producer refunds the excess. This mechanism stabilises revenues over the long term and helps de-risk investment in capital-intensive renewable projects (ENTSO-E, 2024b).
Despite the trade-off between temporal granularity and basis risk, ENTSO-E supports exploring more aggregated reference price mechanisms, as they can enhance market efficiency while still delivering investment certainty (ENTSO-E, 2024b).

Cap-and-Floor CfDs

Cap-and-Floor CfDs define both minimum (floor) and maximum (cap) revenue levels. Producers receive top-up payments when the market price falls below the floor but must return revenue once prices exceed the cap. Between these two thresholds, market revenues accrue to the producer without interference. This bounded risk-sharing arrangement combines stability with a degree of market exposure (ENTSO-E, 2024b).
ENTSO-E advocates for cap-and-floor CfDs as a compromise between full market participation and revenue certainty. These contracts help maintain investment incentives while preventing windfall profits and excessive public expenditure. They are particularly appropriate in high-price environments or for technologies that can tolerate some market variability but still require partial de-risking to attract capital. However, the precise calibration of the cap and floor levels is critical. If the range is too wide, the contract offers insufficient protection; if too narrow, it resembles a two-sided CfD and may distort market behaviour (ENTSO-E, 2024b).

3.3.2 Non Production Based CfDs

Production-based CfDs solve price risks while the volume risk remains unaddressed. Non-production-based Cfds are proposed to manage the dispatch distortions arising from production-based CfDs. The production of an OWF is decoupled from the payment as a result of the CfD. Since the payment from and to the government does not depend directly on the volume, but on the market price signals, bidding and dispatch distortions are avoided. The aim is to make the OWF projects economically viable while ensuring the CfDs avoid creating distortive incentives.

Subtypes

Capability-based CfD

This concept was proposed by the Belgian TSO Elia, and implemented in the Belgian offshore wind tender in the Princess Elizabeth project. While there is no comprehensive document outlining the detailed workings of the CfD model, the concept is explained in their report.
Capability-based CfDs represent a conceptual evolution in contract design wherein support payments are decoupled from the actual production of electricity and instead linked to the theoretical generation potential of the plant, or its "capability" to produce. In this model, remuneration is based on the capacity and expected generation profile under standardised conditions, rather than real-time metered output. The capacity of the reference profile is determined by the production potential determined by the meteorological, topographical and technical conditions. The reference generator should also include the downtime, system curtailment and the technology-specific power curves sensitive to the local weather conditions. Available Active Power (AAP) is used as a tool to define the capacity by Elia (Elia & Orsted, 2024). It is the real-time stream of data furnished by the OWF operators, considering the maximum possible output of the assets for the local weather conditions. This data is difficult to manipulate as it is usually the intellectual property of the manufacturer.

This approach aims to address key inefficiencies inherent in conventional production-based CfDs, particularly the tendency to overproduce during periods of low or negative market prices merely to secure CfD payouts. By rewarding availability rather than output, capability-based CfDs restore short-term market signals and ensure producers respond more rationally to system needs. For instance, a wind farm under a capability-based CfD would not be financially penalised for withholding production during periods of negative pricing, thereby avoiding inefficient dispatch behaviour that burdens grid operators and distorts balancing markets. However, this design introduces significant complexity in determining the reference capability and validating performance. Policymakers must define robust, technology-specific methodologies for estimating capability, accounting for factors such as local resource conditions and technological characteristics. While this may reduce gaming potential relative to conventional CfDs, it also demands a high degree of regulatory oversight and technical standardisation (Kitzing et al., 2024a).

Financial CfDs

Much like Capability-based CfDs, Financial CfDs offer a novel mechanism to stabilise revenue for renewable energy generators while mitigating the drawbacks of conventional CfDs. Unlike traditional CfDs, which are linked to the physical output of a specific asset and reference the hourly day-ahead spot price, financial CfDs operate independently of actual production. They resemble financial forward contracts, with a fixed strike price against a reference market price, and payments are determined based on reference generator volume rather than metered output. The CfD design consists of two components: a fixed hourly payment from the government to the OWF generator and a variable payment linked to the reference output, which is from the OWF generator to the government. The fixed payment is determined based on a competitive bidding process, which is paid hourly and remains constant throughout the contract's duration.

Several approaches have been identified by (Schlecht et al., 2024) for defining reference generation profiles for wind and solar in financial CfDs. One method involves using a mathematical model based on regionally aggregated weather data to derive reference output, as previously trialled by the energy exchange EEX for wind futures. This approach is independent of individual plant decisions, reducing strategic manipulation risks, but its effectiveness as a hedge may be limited by regional averaging, and changes in weather measurement techniques could introduce uncertainties. Another option is to base the reference on the actual output of a sample of physical wind or solar farms, though this risks manipulation if the sample is small. A third approach uses a country or bidding zone's aggregate

wind or solar generation, expressed on a capacity basis (e.g., EUR/MW), similar to market value concepts in German support schemes. This method minimises gaming risks in large bidding zones but remains vulnerable in smaller zones with concentrated generation. Each reference profile balances the trade-off between hedge precision and susceptibility to strategic behaviour, requiring careful design to ensure robust market outcomes.
The primary benefit of this design lies in its flexibility and potential to eliminate operational distortions across market segments. Since remuneration is not linked to actual dispatch decisions, producers face no incentive to manipulate production for the sake of CfD payments. This can facilitate more efficient market outcomes and reduce spillover effects into intraday and balancing markets. Moreover, financial CfDs can be designed to accommodate technology-neutral auctions and allow for broader participation across different investor profiles. Nevertheless, this model is still largely theoretical in public policy frameworks and raises several challenges. Estimating the appropriate benchmark for reference plants introduces a new form of basis risk. It also increases administrative complexity and may necessitate independent verification mechanisms to prevent strategic bidding.

Yardstick CfDs

Yardstick CfDs offer a novel approach by benchmarking the financial settlement of each producer against the average or expected revenue performance of a broader peer group, often comprised of projects within the same technology class or geographical area. In this model, individual producers are remunerated based on the deviation of their actual revenues from a calculated yardstick value, which serves as a synthetic reference (D. Newbery, 2021). The primary purpose of this design is to introduce peer-based discipline and encourage best-practice operational behaviour. For example, producers who outperform the yardstick, perhaps through superior site selection or forecasting would receive higher net remuneration than their peers. Conversely, underperformance relative to the benchmark would result in reduced compensation. This structure can reduce gaming opportunities and sharpen incentives for efficiency, innovation, and system-friendly deployment decisions. By aggregating risks and redistributing rewards within a reference group, yardstick CfDs may also help stabilise investor returns in high-variability environments without requiring intrusive state oversight or rigid contract terms. However, this model also introduces concerns around fairness and transparency. The method for selecting the peer group and defining the yardstick must be robust and well-justified; otherwise, it may favour larger or better-resourced players who can optimise across multiple projects. Moreover, the interdependence of contract outcomes across producers could introduce systemic coordination risks and raise challenges in terms of legal enforceability. While yardstick CfDs remain an emerging concept, they reflect a promising direction for designing next-generation renewable energy support schemes that blend economic efficiency with market integration (Kitzing et al., 2024a).
Non production based CfDs aim to mitigate operational market distortions by decoupling financial payments from actual generation volumes. These instruments encourage producers to make system-friendly operational decisions since payments are not directly dependent on output volume.
This approach creates competitive incentives within the renewable energy market, encouraging producers to optimise their performance continuously. Producers under yardstick CfDs are motivated to innovate and improve their operational practices, fostering an environment of ongoing technological advancement and efficiency gains within the renewable energy sector.

3.3.3 Risk management by CfDs

Table 3.1 summarises the performance of various CfD types across five key criteria using a symbolic scoring scheme, based on ENTSO-E's design recommendations. The table helps to reflect the capacity of each CfD design to address market, operational and investment challenges. The symbols used in Table 3.1 reflect a qualitative scoring approach, where ++ indicates a strongly positive assessment, + a positive outcome, +- a mixed or context-dependent result, – a strongly negative outcome, and - a negative effect (ENTSO-E, 2024b).

Criterion	Prod. CfD			Non-prod. CfD	
	Hourly Price	Yearly price	Price cap and floor	Financial CfD	Capability-based CfD
Price risk	+	+	+	+-	+
Volume risk	- -	- -	-	+-	+
Asset siting	- -	+-	-	++	-
Dispatch	- -	–	-	++	++
Regulatory risk	-	-	-	- -	+-

Table 3.1: Comparison of CfD types based on different criteria (ENTSO-E, 2024b)

Hourly price-based two-sided CfDs are effective at covering price risk (+), but they perform poorly across most other dimensions. They are particularly susceptible to dispatch distortions (–), as they incentivise generators to produce regardless of system needs, especially during low or negative price periods. These contracts also encourage volume maximisation over system alignment, negatively affecting asset siting (–) and complicating risk hedging in volatile markets.

Yearly price-based CfDs using ex-ante reference pricing suffer from similar issues as hourly CfDs. Ex-post reference pricing improves predictability and reduces dispatch distortions (- rather than –). However, both formats show limited ability to reflect locational or temporal system needs, leading to marginal improvements in asset design incentives (+-), and volume risks remain unmitigated (–).

Cap-and-floor price CfDs allow for some market exposure, encouraging more system-friendly dispatch behaviour (-). They reduce price risks by binding them between upper and lower strike price bounds. However, their effectiveness depends heavily on the careful calibration of cap and floor levels. They remain less effective in incentivising optimal asset siting or managing regulatory complexity, performing moderately (-) across several dimensions.

In contrast, non-production-based CfDs show more favourable performance. Capability-based CfDs score strongly (++) on dispatch efficiency by decoupling payments from actual output and removing incentives to generate at inefficient times. They also provide solid risk hedging for both price and volume (+) and are relatively future-proof in regulatory terms (+-). However, they may still encourage volume maximisation in asset siting if the reference profiles are not adequately calibrated.

Financial CfDs also score highly (++) in dispatch alignment and offer flexibility in bidding and investment strategies. They are particularly effective in incentivising efficient asset siting, especially under yardstick or benchmark models. However, they show mixed performance on risk hedging (+/-) due to uncertainty about how closely real plant output will match the reference profile. Regulatory risk (–) is a key concern, particularly in defining and managing appropriate reference generators.

3.4 Distortions and Inefficiencies Introduced by CfDs

While CfDs have proven effective in de-risking renewable investment, their design and implementation can also introduce unintended consequences—namely, market distortions and inefficiencies. The remainder of this chapter explores these challenges, focusing on how CfD structures interact with electricity market signals and system operation.

3.4.1 Operational distortions

Produce and forget

The deployment of CfDs can lead to a distortive response from the wind generators to maximise production irrespective of the price dynamics in the market (Kitzing et al., 2024a). The productionbasedsug CfDs can have distortive characteristics due to which the generators tend to produce and forget. Under a typical production based CfD design, the generators earn a fixed income based on the strike price, regardless of the market price. This means that the revenues depend entirely on the volumes exported, not on the market value of the power. The generators aim to maximise output rather than optimising the output to time it at a moment of high value. The CfD generators have little to no incentive to schedule maintenance during periods of low demand or high congestion. These certain CfD designs mute the price signals and create the so-called *produce and forget* distortions (Schlecht et al., 2024).

Dispatch Distortions at Extreme Prices

CfD pays the generators when the market prices are lower than the strike price, which can warp the generator's operating decisions in extreme price instances. When the prices fall below the plants' marginal costs, which are zero in the case of OWFs, a conventional CfD design encourages continued production. The government pays for the difference between the strike price and the reference market price even when the prices are negative, leading to the wind farms being mute to the price signals (Hirth & Kotte, 2024). Without additional conditions, the CfDs will keep producing at negative prices and thus would not shut down when the system needs them to. On the other hand, when the prices are high, the clawback to the government can act as a tax, eroding any profit from generation in those hours. This means that the generators have no extra incentive to ramp up production when there is a need. Moreover, if the intraday prices are to drop after the day ahead market, the plant might choose to curtail output and buy power from the market to avoid the clawback. Both behaviours are inefficient and the design of the CfD can trigger these behaviours.

Intraday and Balancing Market Distortions

Once the day ahead market is cleared, the payment to the generators is fixed based on the difference between the spot price and the CfD strike price. The generators can treat this impending payment as an opportunity cost in the later markets. This can lead to distortive bidding behaviour in these markets, putting an upward or downward pressure on the prices (Schlecht et al., 2024).

High day ahead price, Lower Intraday Price

If the day-ahead price is very high, the generator is in a clawback situation. Suppose the day ahead cleared at 100 €/MWh and the strike price is 10 €/MWh, meaning the generator will be paying 90 €/MWh as the clawback. If the intraday price falls significantly while staying positive, say 80 €/MWh, the generator can profit by purchasing this power to cover its day-ahead commitment instead of producing and paying the clawback. Here, the OWF will curtail even though the market price is well above its marginal costs, which is inefficient from a system perspective. This requires a pretty large drop after the day-ahead stage; historical analysis in Germany found that this drop is only a few euros on average (Kulakov & Ziel, 2019). However, as the penetration of renewable energy increases, the likelihood of this behaviour increases.

Low Day ahead price, Negative Intraday price

This case arises when the day-ahead price is low and the OWF expects a CfD payout and then the intraday prices turn negative. Ideally, a generator should curtail after prices turn negative. However, if the generator is receiving a CfD payout for producing at negative price hours, this price signal gets blurred. If the CfD payout is larger than the absolute intraday price, the generator will keep on producing, even when the intraday prices are negative. For example, if the strike price is 30 €/MWh and the market price is 10 €/MWh, the CfD payout will be 20 €/MWh. Therefore, in the intraday market, the generators will bid if the prices are above -20 € /MWh as the payout would be positive. This behaviour is observed not only in CfDs but also in all production-tied subsidy schemes.

This creates an upward or downward pressure on the prices, which can affect not only the operational behaviour in the day-ahead market but can also propagate to the intraday and balancing market.

The impact on the other market segments will not be studied in this thesis, as this thesis focuses more on the operational behaviour in the day ahead market.

3.4.2 Investment and lifecycle distortions

Some CfD designs flatten the revenue to a fixed strike price, leading to long-term distortions in the wind farm's decision making (Hirth & Kotte, 2024). Under competitive market conditions, the wind farm developers choose to invest in system friendly designs (D. Newbery, Pollitt, Reiner, & Taylor, 2021). This can entail large rotors or optimal orientation so that the power is maximised during high value hours. A conventional CfD design disincentivises such designs because it rewards the generators based on the total MWh produced and not the timing of the produced power. Similarly, the CfDs encourage a baseload style of investment for dispatchable plants. There is no added benefit provided for flexibility (ramping and storage functions) since the contract pays the same for each MWh (Kitzing et al., 2024a).

A traditional CfD design often mutes the price signals, leading to maintenance or retrofits that would be optimal under regular market prices can be mistimed under a CfD. In periods of high demand and high prices, an OWF without CfD support might invest in maintenance or life extension to capture the high prices. Conversely, a CfD does not provide strong price signals; therefore, OWFs can under-invest in upkeep, leading to lower output and revenues. Similarly, for low prices, the generator does not react and keeps producing power to continue collecting the contract payments instead of investing in upkeep. Furthermore, a generator might delay the replacement of an old turbine to avoid missing the CfD payments instead of installing a more efficient turbine. This leads to inefficient capital allocation and a delayed turnover on the assets.

3.4.3 Bidding distortions

Apart from physical dispatch, the wind farms can lead to changes in the bidding behaviour by the generators. This can affect the price formation without necessarily impacting the dispatch. CfD holders can incorporate the expected payout or clawback as an opportunity cost in their bids to maximise their revenue (Hirth & Kotte, 2024). The generators may tend to alter their bids to suit the market conditions. During clawback hours, the generators are given a premium over their selling price, while during payout periods, they subtract the value from their selling price. For instance, an OWF generator expecting a payout of 50 € /MWh may be willing to bid at -50 € MWh instead of 0 € /MWh. Similar logic holds for clawback periods, where the willingness to sell is at a higher price to incorporate the clawback. This behaviour can distort the price formation not only in the day ahead market but also in the intraday market, creating artificial upward pressure when many CfD units are being paid and downward pressure when the generators are paying back (Kitzing et al., 2024a).

Production based CfDs are good at reducing revenue uncertainty by covering a majority of the price risk, however, they fail to address the volume risk. Solutions to solve some of the distortions discussed above include discontinuing payments at periods of negative prices. This, however, may create additional uncertainties like revenue gaps under negative prices. A common tweak to the production based CfDs is to include a longer reference period (monthly or yearly averaged prices) instead of hourly prices for the CfD. This can smooth out some of the price crests and troughs, potentially reducing the *produce and forget* incentives. Denmark's Thor offshore wind tender, for example, used a 12-month rolling average reference price and skipped payments in negative price hours (European

Commission, 2021).
Another solution explored in this thesis is the decoupling of CfD payments from the actual output as formulated in the non-production-based CfDs. The payments are based on a reference output profile rather than the plant's generation. This is aimed at giving producers a revenue hedge without affecting their incentive to follow market prices. The generators receive a pre-decided baseline revenue, but any deviations from the reference affect their profits at market prices. While largely addressing the price and volume risk, this design exposes the generators to the basis risk.

3.4.4 Basis risk

In the context of an offshore wind CfD, basis risk refers to the risk that the output profile of a wind farm's electricity market earnings does not exactly match the reference. It is essentially a mismatch risk that arises when the actual output of the generator differs from the reference turbine due to locational and technology-related differences. If a wind farm operates in a location with suboptimal wind conditions compared to the reference turbine, or if it uses a turbine technology with a higher efficiency, the gap between the expected CfD payment and the actual market revenue becomes more pronounced, leading to unhedged risks. This can also influence the behaviour of the generators to adapt to these differences, causing distortions (Schlecht et al., 2024).
Locational distortions are also a concern for CfD designs that rely on a reference profile. Wind patterns, topography, and local climate conditions vary across different sites. This means that there is a likelihood of significant deviation from the reference turbine for the generators. As a result, projects in regions with weaker wind resources may significantly underperform compared to the reference turbine. As a result, projects located in regions with better wind conditions than the reference turbine will consistently outperform the reference output, enabling them to retain more market revenue. Conversely, the wind farms located in weaker wind regions may generate less than the reference yet owe payments to the government. This imbalance can distort the investment incentives by drawing capital towards regions whose generation profiles match the reference. This distortion reduced the system-wide efficiency (Kitzing et al., 2024a).

In addition to locational effects, *technology-based distortions* emerge when the CfD settlement relies on a standardised reference turbine output. Wind turbines differ substantially in their design, having different cut-in speeds, rated power curves and efficiencies. These differences are pronounced over a long period and varying wind conditions. Since the payment to the government is tied to the reference generator, more efficient turbines which regularly outperform the reference generator's output, receive higher revenues. Additionally, the temporal generation profile of turbine technologies plays a critical role. Technologies that can maintain output during periods of low wind, when overall system generation is scarce and market prices are typically higher, can outperform others by capturing greater revenues. This ability to generate during high-value hours provides a competitive advantage. This shows that there can be a technology related bias, which is termed as the technology-specific basis risk (Kitzing et al., 2024a).

This thesis aims to quantify the risks and inspect them across different CfD cases. The numerical depiction of the risk metrics will help garner a better idea of the performance of the CfDs. The possible distortions mentioned above, being triggered by specific CfD designs, can be judged based on the metrics. The thesis aims to capture the operational behaviour of the OWF generators in response to the implementation of the CfDs. The wind farms in this project aim to optimise their response under the condition of a CfD design. They do not aim to game the system and behave strategically in this project; therefore, some of the distortions will not apply to this study. The generators can only change the bid volume input in the system while continuing to bid at marginal costs (which are zero for wind). The distortions observed at extreme prices, putting upward and downward pressure on the market, will not be observed here as the wind farms cannot bid strategically.
Additionally, only the day-ahead market is considered for observing the operational behaviour and

the impact of technology choices in this study. Therefore, the distortions arising in other market segments cannot be explicitly modelled.

3.5 Metrics Table

Table 3.2: Summary of General Characteristics, Price Risks, and Volume Risks in CfD Context

General Characteristics	**Price Metrics**	**Volume Metrics**
Revenue	Flat price risk	Physical restriction (congested HVDC)
Curtailment	Price collapse risk	Capacity calculation
Total wind generation	Conv. low price	Capacity allocation
Export during 0 prices	Conv. medium price	
Export during non-0 prices	Conv. high price	
Congestion	Price Δ due to bids	
	Non-intuitive price	

General Characteristics in the context of electricity markets refer to key performance indicators for generation assets under CfD arrangements. Revenue captures the core financial outcome of energy sales, which can vary significantly depending on whether the CfD is conventional or financial. Curtailment reflects the volume of electricity a generator could have produced but was forced not to due to system constraints or market signals, often exacerbated by poorly designed incentives in output-linked CfDs. Total wind generation serves as a measure of renewable output, directly impacting revenue when payments are tied to actual production. Export metrics—export during 0 prices and export during non-0 prices—highlight whether generation aligns with market value. For instance, exporting at zero prices is typically wasteful and often occurs under contracts that reward output regardless of price. Congestion rents and congestion measure how transmission limitations influence market efficiency and generator income, revealing whether a system is delivering power optimally or facing bottlenecks.

Price Risks encompass the uncertainties associated with fluctuating market prices that affect the financial outcomes of CfDs. Flat price risk refers to scenarios where price volatility is low, limiting potential gains from price differentiation. Price collapse risk highlights situations where spot market prices drop sharply, reducing the value of generation and stressing generators financially. The labels conv. low, medium, and high price refer to typical price bands under conventional market operations, which determine the net payments under CfDs. CfDs using fixed strike prices are vulnerable to distorted outcomes if these market prices shift unexpectedly. Price Δ due to bids indicates that strategic or opportunistic bidding in day-ahead or intraday markets can lead to altered local prices, affecting CfD outcomes and potentially causing gaming behaviour. Non-intuitive pricing refers to scenarios where prices do not reflect true system conditions, often caused by poorly aligned market rules or CfD structures that mute proper price signals.

Volume Risks relate to uncertainties in the actual quantity of electricity that can be delivered or exported, due to system limitations or market mechanisms. Physical restriction, such as through congested High Voltage Direct Current (HVDC) links, can prevent a generator from delivering its output even if market prices are favourable, resulting in revenue loss. Capacity calculation addresses the risk of inaccurately estimating how much capacity is available or usable for generation or transmission, which can affect contract sizes and payment expectations. Capacity allocation involves how limited transmission or export capacity is distributed among competing generators, which can lead to unequal access and financial disadvantage for certain assets, particularly in regions with frequent congestion.

3.6 Conclusion

This chapter has presented a comprehensive overview of CfDs as a crucial policy instrument for enabling large-scale offshore wind development, particularly in OBZs. It began by establishing the need for CfDs in de-risking capital-intensive offshore wind investments, especially in the context of volatile market prices and complex grid interactions.

Different CfD design typologies were introduced, including both production-based and non-production-based CfDs. Each design was evaluated in terms of its ability to address price and volume risks, encourage efficient dispatch, and influence long-term investment behaviour. The chapter also highlighted the potential inefficiencies and market distortions that poorly designed CfDs can introduce, such as the "produce and forget" incentive, dispatch distortions during extreme price events, and lifecycle or technology biases.

Finally, the chapter established a set of evaluation metrics that will be used throughout this thesis to analyse the performance of various CfD schemes. These metrics contain price risk, volume risk, and operational behaviour, providing a framework to systematically compare policy designs. This foundation sets the stage for the case studies in the following chapters, where the practical impact of different CfD structures on offshore wind operations and system efficiency will be explored. After concluding the literature survey, the next part of the thesis will focus on building a model to translate key policy designs into a quantitative market model. The aim is to operationalise some of the concepts discussed in the literature.

4 | Methodology

This chapter establishes the framework for answering the research questions framed at the beginning of the thesis. After reviewing the literature about the market clearing process and listing the different CfD designs, this part of the report aims to create a model to study the CfD schemes within the context of the market clearing process and reflect on their impact on the day ahead market and the operational behaviour of the offshore wind farm operators. The criteria used to study the CfDs are quantified and compared across cases to evaluate their performance.

4.1 Research Approach

The central research question guiding the study is:
"How can Contracts for Difference (CfD) schemes be designed and implemented in offshore bidding zones to incentivise investment in offshore wind farms, and how do they influence operational behaviour and technology preferences?"
To explore this question, a model representing a market clearing is constructed. The model serves as the foundation, simulating the market conditions under various CfD schemes, enabling an in-depth analysis of their implication for offshore wind energy investment and market behaviour.

The first step involves detailing the intricacies of the model while defining its limitations and constraints. This step is crucial to accurately capture the dynamics of an integrated electricity market with renewable generation. The model framework represents a grid network that includes renewable energy sources, onshore grid attenuations, and offshore grid topology.

Once the model is defined, the next step is to solve the market clearing which will act as the reference case for this study. The information received from this model will provide a benchmark for comparing other cases. The market clearing is simulated for every hour in the time series, representing the FBMC process, balancing the demand and supply in the grid network, subject to the system constraints and pricing mechanisms.

The next step is to define the test cases designed to answer key research questions. The test cases represent the different CfD Schemes that need to be studied within the framework of the OBZs and the impact of these schemes on the day-ahead market. The test cases are drawn from the literature reviewed in Chapter 3 and their outcome will help identify the optimal response of the wind farms under different CfD designs.

Finally, the model's outcomes are compiled after running the test cases, followed by an analysis of their implications. Key outputs include visualising the price duration curve, assessing the profit variability under different CfD schemes, examining government clawbacks, and understanding the operational behaviour of the wind farms.

4.2 Model setup

The model in 5.1 is set up in Julia due to the mathematical and functional prowess of the programming language. The easy syntax, high performance, and suitability for scientific operations make it an ideal choice. The optimisation problem is solved using the Gurobi solver, known for its high speed in handling linear programming problems. The ability of Gurobi to handle constraints and multiple variables makes it easier for effectively solving complex optimisation problems. A time series of 744 steps is considered, each step representing an hour, and representing the data that captures seasonal fluctuations.

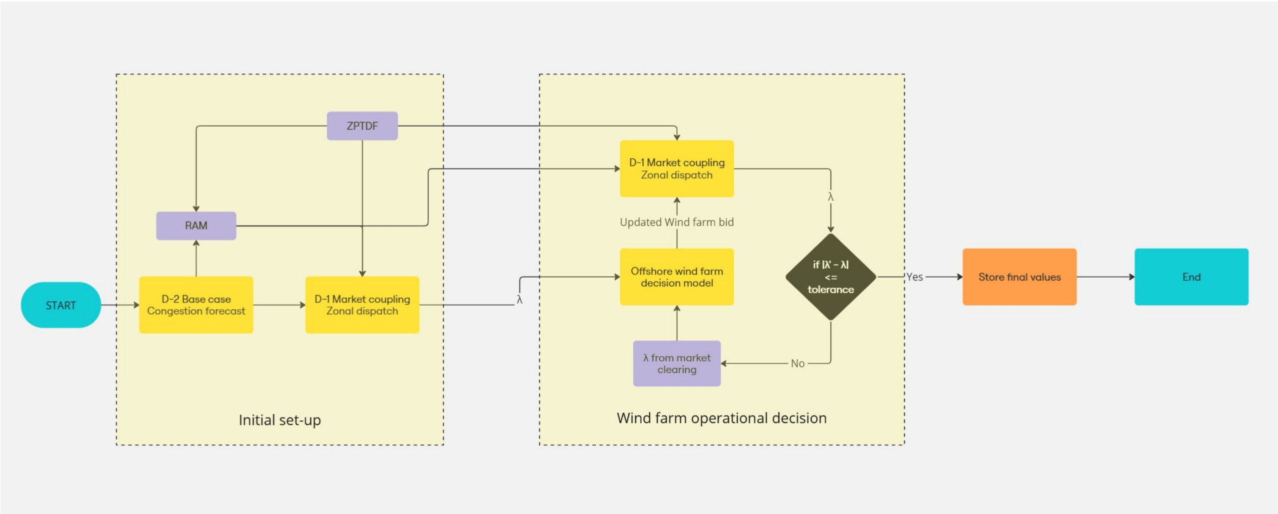


Figure 4.1: Logic flowchart

The figure above illustrates the structure of the model for the simulation. After collecting the data, the initial step for the market clearing is performed to define the input parameters for the subsequent stages of the part of the model. The market clearing as described in (Kenis et al., 2023) requires the use of three steps wherein the first is the establishment of a D-2 base case scenario that entails the definition of the optimisation problem. The next step is the D-1 day ahead case which is the main focus in this model and responsible for the market clearing. The D-0 or redispatch case is not of particular importance here as the effect of the CfD is more prevalent on the day ahead market.

The decision of the wind farm is an important aspect of the model. The next block of the flowchart represents the decision by the OWF operators when exposed to the market prices as a response to the CfD scheme in place. The input and output parameters are distinctly mentioned for each of the steps of the model.

The initial setup of the logic flowchart is based on the framework developed by (Kenis et al., 2023). The mathematical model representing the OBZ under FBMC has been adapted from this work. The thesis extends the original model by incorporating an additional decision-making block for OWFs, enabling the analysis of their operational behaviour under various support schemes. The underlying model was sourced from the associated GitHub repository (Kenis & Bruninx, 2024). The inclusion of the CfD decision logic within the OWF block introduces a new extension to the existing model, allowing for the investigation of behavioural changes induced by different CfD designs.

4.3 Market Clearing Process

Set	Description	Stage
N	Nodes in zone z	All
G	Dispatchable Generators g	All
Z	Zones	All
L	AC Lines	All
H	DC Lines	All
R	Renewable intermittent generators	All
T	Timesteps	All
X	Dispatchable electrolyzers $h2$	All

Table 4.1: Sets used in the electricity market model

Parameter	Description	Stage
MC_g	Marginal Cost of generator g [€/MWh]	D-0, D-1
CC	Curtailment Cost of Offshore Wind Farm (€/MWh)	D-0, D-1
Q^s_g	Generating capacity of dispatchable generator g [MW]	D-0, D-1
Q^d_n	Demand for electricity at node n [MW]	D-0, D-1
$zPTDF^z_l$	Zonal PTDF for AC line l and zone z	D-1
$nPTDF^{n(h)}_l$	Nodal PTDF for AC line l and node $n.h$ indicates starting or ending end of a DC flow	D-1
R_n	Renewable injection for each node [MW]	All
$I^{AC}_{l,z}$	Flow direction on cross-border AC line l from/to zone $z \: \epsilon - 1, 0, 1$	D-1
$I^{DC}_{h,z}$	Flow direction on cross-border DC line h from/to l zone $z \: \epsilon \: -1, 0, 1$	D-1
$I^{DC}_{h,z,z'}$	Flow direction on cross-border DC line between zones z & $z' \: \epsilon \: -1, 0, 1$	D-1
$I^{ACDC}_{n(h-),h}$	Flow direction on cross-border DC line into/away from node $n(h-)$, $\epsilon - 1, 0, 1$	D-1
$I^{ACDC}_{n(-h),h}$	Flow direction on cross-border DC line into/away from node $n(-h)$, $\epsilon - 1, 0, 1$	D-1
RAM^-_l	Minimum RAM of AC line l [MW]	D-1
RAM^+_l	Maximum RAM of AC line l [MW]	D-1
$NTC^+_{z,z'}$	Maximum NTC of DC line connecting zones z and z' [MW]	D-1
$NTC^-_{z,x}$	Minimum NTC of DC line connecting zones z and z' [MW]	D-1
$\bar{F}_l$	Upper transmission capacity limit for AC line l	D-0
$\bar{F}^{DC}_h$	Upper transmission capacity limit for DC line h	D-0
α	Redispatch cost markup	D-0
WTP_{h2}	Willingness-to-Pay of electrolyzer $h2$ [€/MWh]	All
Q^d_{h2}	Installed capacity (demand) for electricity at electrolyzer $h2$ [MW]	All
λ_z	Spot price at zone z	OWF
SP	Strike price for CfD	OWF

Table 4.2: Parameters used in the electricity market model
(Kenis et al., 2023)

Decision Variable	Description	Stage
v_g	Reference production of dispatchable generator g	D-0, D1
c_n	Curtailment of at node n	D-1
f_l^{AC}	Flow on AC line l	D-1
f_l^{DC}	Flow on DC line l	D-1
p_z	Net position at zone z	D-1
p_z^{FB}	Net position at zone z impacting the flow-based domain	D-1
u_g	Upward adjustment of scheduled output of generator g	D-0
d_g	Downward adjustment of scheduled output of generator g	D-0
Δc_n	Curtailment adjustment of scheduled output of OWF at node n	D-0
Δf_h^{DC}	DC flow adjustment at line h	D-0
e_{h2}	Relative production of dispatchable electrolyser $h2$	D-0, D1
u_{h2}	Upward adjustment of scheduled input at electrolyzer $h2$	D-0
d_{h2}	Downward adjustment of scheduled input at electrolyzer $h2$	D-0
q_n^{OWF}	OWF operational decision at node n [MWh]	OWF

Table 4.3: Decision variables in the electricity market model
(Kenis et al., 2023)

4.3.1 D-2 Base case

The base case establishes the predicted power flows two days before the actual power market clearing. This step is essential to determine the flow based parameters based on the projected power flows for a nodal market clearing, which is used in the base case. The nodal PTDF matrix is defined based on the physical characteristics of the grid and its electrical properties (Van den Bergh, Boury, & Delarue, 2014). It quantifies how active power injections at nodes influence flows on transmission lines. A is the line to node incidence matrix, and B_l is the diagonal matrix of line susceptances. It is expressed as:

$$\mathrm{PTDF}_n^{\ell} = (B_\ell \cdot A) \cdot \left(A^\top \cdot B_\ell \cdot A\right)^{-1} \tag{4.1}$$

GSKs are used to allocate zonal power injections across individual nodes within a zone. Broadly, two main strategies exist for determining GSK values. The flat GSK strategy assumes that all generators within a zone contribute equally to the net injection, irrespective of their capacities. In contrast, the capacity-weighted strategy distributes injections proportionally based on the installed generation capacity at each node.

$$\mathrm{GSK}_{n,z} = \frac{\sum_{g \in g(n)} Q_s^g}{\sum_{n \in \mathcal{N}} \sum_{g \in g(n)} Q_s^g} \tag{4.2}$$

The GSK matrix is structured such that each row corresponds to a node and each column to a zone. Each entry represents the share of zonal injection attributed to a particular node. For a given zone, the sum of all GSK values across its nodes equals 1, ensuring that 100% of the zonal generation is properly distributed among its constituent nodes.
The GSKs are an input to the day ahead market clearing, and together with the reference flows F_l and the reference position p_z, which is an output of the base case, are used to calculate the zonal

PTDF and RAM matrices.

Objective Function

$$\min_{v_g, e_h, p_z, c_n, f_h^{DC}, f_l^{AC}} GC = \sum_{g \in G} MC_g \cdot Q_g^s \cdot v_g + \sum_{n \in N} c_n \cdot CC - \sum_{h2 \in H2} WTP_{h2} \cdot Q_{h2}^d \cdot e_{h2} \tag{4.3}$$

Constraints

$$\sum_{g \in G} Q_g^s \cdot v_g + \sum_{n \in N} R_n - c_n - Q_n^d - \sum_{h2 \in H2} Q_{h2}^d \cdot e_{h2} = p_z, \quad \forall n \in N \tag{4.4}$$

$$\sum_{l \in L} f_l^{AC} \cdot I_{l,z}^{AC} + \sum_{h \in H} f_h^{DC} \cdot I_{h,z}^{DC} = p_z, \quad \forall n \in N \tag{4.5}$$

$$f_l^{AC} = \sum_{n \in N} nPTDF_l^n \left[\sum_{g \in G(N)} Q_g^s + R_n - c_n - Q_n^d - \sum_{h2 \in H2} Q_{h2}^d \cdot e_{h2} - \sum_{h \in H} f_h^{DC} \cdot I_{h,n}^{DC} \right], \quad \forall l \in L \tag{4.6}$$

$$-\overline{F}_l \leq f_l^{AC} \leq \overline{F}_l, \quad \forall l \in L \tag{4.7}$$

$$-\overline{F}_h^{DC} \leq f_h^{DC} \leq \overline{F}_h^{DC}, \quad \forall h \in H \tag{4.8}$$

$$0 \leq v_g \leq 1, \quad \forall g \in G \tag{4.9}$$

$$0 \leq c_n \leq R_n, \quad \forall n \in N \tag{4.10}$$

$$0 \leq e_{h2} \leq 1, \quad \forall h2 \in H2 \tag{4.11}$$

$$\sum_{h \in H} f_h^{DC} \cdot I_{h,n}^{DC} = R_n - c_n - \sum_{h2 \in H2} Q_{h2}^d \cdot e_{h2}, \quad \forall n \in N' \tag{4.12}$$

The objective function serves the purpose of minimising the generation costs as a function of several decision variables including the relative production of a generator v_g, the curtailment at a node c_n, position of a zone p_z, electrolyser production $e_h 2$ and the flow on the DC and AC line f_l^{DC} and f_l^{AC} respectively. The first term of the equation represents the cost of generation for a power producer which is marginal cost times the scheduled quantity of dispatch of the generator. The second term which is the curtailment times the cost of curtailing power for a generator, $c_n \cdot CC$. This represents the congestion costs which are paid by the TSO to the generator where there is a need to curtail power. The last term represents the money paid to the system in the case of there being demand from the offshore electrolysers. The WTP_{h2} is the willingness to pay of the H_2 actors for a MWh of electricity for producing hydrogen. $WTP_{h2} \cdot Q_{h2}^d \cdot e_{h2}$ is the willingness to pay of electrolysers times the capacity of H_2 times the production of H_2 at that particular time step and node.

The constraint (4.2) is used to define the position of the zone based on the nodal power balance equation. The relative production of the generators, $Q_d^s \cdot v_g$ and the renewable injection at each node, R_n subtracted by the curtailment c_n and the demand Q_n^d at each node subtracted by the elastic hydrogen production $Q_{h2}^d \cdot e_{h2}$ defines the position of the zone. The constraint (4.3) enforces the position obtained in the constraint (4.2) to also obey the flow variables f_l^{AC} and f_h^{DC} in the AC and DC lines respectively and the parameters $I_{l,z}^{AC}$ and $I_{h,z}^{DC}$ which that define the direction of the flow in the AC and DC lines. The parameters can either be 1,0 or -1 with 1 representing flow to go outside the zone of reference and vice-versa for -1 while 0 represents no cross border flow. Equation (4.3) depicts the impact of the flow of power along a line on the whole transmission network. The nodal PTDF matrices which have been calculated are multiplied to the demand subtracted by supply of the particular node. Also injections or extractions from the DC lines affecting the node are considered and represented by $f_h^{DC} \cdot I_{h,n}^{DC}$. The nodal PTDF vaues represent the sensitivity of all lines to the injection in a node n and therefore this constraint estimates the power flow on each AC line. Constraint (4.5) limits the fluctuation of the flow f_l^{AC} on an AC line l between the physical limits of each respective AC line. Similarly, constraint (4.6) limits the DC flow on a line h within its physical limitations. The relative production factor of v_g is limited between 0 and 1 in constraint (4.7) and the same is reflected for relative electrolyser output e_{h2}. The curtailment of the renewable generators c_n has a lower bound of 0 and a maximum of R_n which is the maximum renewable output possible at the node n at a certain instance of time. This is represented in the constraint 4.8. Finally, the constraint 4.10 shows that the power flow in a DC line h, all of which are offshore connections in the model, is maintained and that all the power flow in the system is accounted for.

4.3.2 D-1 Market clearing

After simulating the base case scenario, the output of predictive power flows is used to calculate the flow-based parameters, which in turn are used to solve the market clearing. The day ahead D-1 model clears the market based on the zonal PTDF and RAM values and the curtailment for the renewables predicted in the base case scenario.

Objective Function

$$\min_{v_g, e_{h2}, p_z^{FB}, c_n, f_h^{DC}, f_l^{AC}} \quad \begin{aligned} GC = &\sum_{g \in G} MC_g \cdot Q_g^s \cdot v_g + \sum_{n \in N} c_n \cdot CC \\ &- \sum_{h2 \in H2} WTP_{h2} \cdot Q_{h2}^d \cdot e_{h2} \end{aligned} \tag{4.13}$$

Constraints

$$\begin{aligned} &\sum_{g \in G} Q_g^s \cdot v_g + \sum_{n \in N} R_n - c_n - Q_n^d \\ &\qquad - \sum_{h2 \in H2} Q_{h2}^d \cdot e_{h2} = p_z, \quad \forall z \in \mathcal{Z} \end{aligned} \tag{4.14}$$

$$\sum_{l \in L} f_l^{AC} \cdot I_{l,z}^{AC} + \sum_{h \in H} f_h^{DC} \cdot I_{h,z}^{DC} = p_z, \quad \forall z \in \mathcal{Z} \tag{4.15}$$

$$p_z^{FB} = p_z - \sum_{h \in H} f_h^{DC} \cdot I_{h,z}^{DC}, \quad \forall z \in \mathcal{Z} \tag{4.16}$$

$$\begin{aligned} -RAM_l^- \leq &\sum_{z \in \mathcal{Z}} zPTDF_l^z \cdot p_z^{FB} \\ &+ \sum_{h \in H} f_h^{DC} \left[nPTDF_l^{n(h-)} \cdot I_{n(h-),h}^{ACDC} + nPTDF_l^{n(-h)} \cdot I_{n(-h),h}^{ACDC} \right] \\ &\leq RAM_l^+, \quad \forall l \in L \end{aligned} \tag{4.17}$$

$$-NTC_{z,z'}^- \leq \sum_{h \in H} f_h^{DC} \cdot I_{h,z,z'}^{DC} \leq NTC_{z,z'}^+, \quad \forall z, z' \in \mathcal{Z} \tag{4.18}$$

$$0 \leq v_g \leq 1, \quad \forall g \in G \tag{4.19}$$

$$0 \leq c_n \leq R_n, \quad \forall n \in N \tag{4.20}$$

$$0 \leq e_{h2} \leq 1, \quad \forall h2 \in H2 \tag{4.21}$$

$$\begin{aligned} \sum_{h \in H} f_h^{DC} \cdot I_{h,n}^{DC} = R_n - c_n \\ - \sum_{h2 \in H2} Q_{h2}^d \cdot e_{h2}, \quad \forall n \in N' \end{aligned} \tag{4.22}$$

The objective function, like the base case scenario in aims at minimising the generation costs for the day ahead market. The equations 4.12, 4.13 are the same as the equations 4.2 and 4.3 in the base case that define the power balance equation and determine the relative position of the zone. Along with the constraints also serve to limit the position within realisable values with respect to the AC and DC flows. The additional constraints in the market clearing process include the determination of the position in the flow based domain p_z^{FB}. The model uses AHC as mentioned in section 2.3, which focuses on the interaction of DC lines and the AC lines and the impact the DC line has on the AC line is represented by the constraint (4.15). The paramters $nPTDF_l^{n(h-)}$ and $nPTDF_l^{n(-h)}$ are the nodal power transfer matrices that are used to calculate the flow on the AC lines as a result of power flow on the DC lines, wherein $n(h-)$ and $n(-h)$ represent the start and end of a DC line respectively. $I_{n(h-),h}^{ACDC}$ and $I_{n(-h),h}^{ACDC}$ is either 1,0 or -1 depending on the direction of flow of power (it is 1 if the flow is toward the node $n(h-)$ and vice versa). The constraint (4.16) limits the DC flow in the line h between zone z and z' within the NTC limits for the two zones in question. Constraint 4.17-4.20 are similar to the constraints 4.7-4.10 in the base case model.

Redispatch is the next step in the market clearing process, but, in this model it does not affect the wind farm decision. In this model, OWFs receive CfD payments based on the electricity they are scheduled to produce in the DA market. However, during the redispatch phase, TSOs may adjust power flows to balance the grid. This can alter the amount of electricity the wind farms actually dispatch, resulting in variations in CfD revenue. If there is a shortfall or surplus, the TSO either compensates the OWF or requests a reimbursement. While redispatch affects revenue, it does not impact the wind farm's initial decisions in the market-clearing process.

4.4 Offshore Wind Farm Decision

4.4.1 The Decision Problem of Offshore Wind Farms

In offshore bidding zones (OBZs), wind farm operators are assumed to behave as rational agents seeking to maximise their revenue in each market interval. The central decision variable is the bid quantity $q_t^{\text{OBZ},n}$, representing the volume of electricity offered by asset n in hour t. The operator's objective is influenced by the prevailing market price λ_t^{OBZ}, support scheme incentives in the form of CfD policy, and physical constraints such as generation potential. The curtailment cost (CC) in the thesis has been considered to be 0; therefore is excluded from the revenue optimisation problem of the wind farms.
The general revenue maximisation problem for each wind farm can be expressed as:

$$\max \quad \text{Rev}_n^{OBZ} = \sum_{t \in T} \text{Payout}_t(q_t, \lambda_t) \tag{4.23}$$

$$\text{subject to:} \quad 0 \leq q_t^{\text{OBZ},n} \leq R_{n,t} \quad \forall t \in T \tag{4.24}$$

Here, Payout_t varies depending on the implemented CfD design. The model captures the interdependence between OWF bidding and market price formation through iterative feedback between the decision block and market-clearing model.

4.4.2 Offshore Turbine Technology

To systematically analyse the impact of different CfD mechanisms within OBZs, the initial step involved examining the influence of turbine technology selection on offshore wind farm power output. A comprehensive literature review identified common turbine technologies deployed in the North Sea region (Musial, Beiter, Nunemaker, & Heimiller, 2019; IRENA, 2021). Based on this assessment, three distinct turbine models were selected, each characterised by unique power curves, to capture representative technological variability necessary for meaningful comparative analyses.

Hourly wind speed data U_{10}, V_{10} measured at 10 meters above sea level were initially obtained. The resultant wind speed W_s and wind direction W_d were computed as:

$$W_s = \sqrt{U_{10}^2 + V_{10}^2} \tag{4.25}$$

$$W_d = \arctan\left(\frac{-U_{10}}{-V_{10}}\right) \times \frac{180}{\pi} + 180 \tag{4.26}$$

An optimal wind farm orientation θ_{opt} was determined using an optimisation approach to maximise annual wind exposure, described mathematically as:

$$\theta_{\text{opt}} = \underset{0^\circ \leq \theta \leq 360^\circ}{\text{arg}, \max} \left(\sum_{t=1}^{8760} W_s(t) \cdot \cos(W_d(t) - \theta) \right) \tag{4.27}$$

The wind speeds measured at 10 metres W_s^{10m} were subsequently extrapolated to turbine-specific hub heights H using the logarithmic wind profile law, accounting for offshore surface roughness length $z_0 = 0.0002m$ (Manwell, McGowan, & Rogers, 2010)

$$W_s(H) = W_s(10, m) \times \frac{\ln\left(\frac{H}{z_0}\right)}{\ln\left(\frac{10}{z_0}\right)} \tag{4.28}$$

DTo reduce computational complexity associated with processing the full annual dataset (8760 hourly timesteps), the data was compressed into a representative month consisting of 744 hourly values. This temporal reduction was achieved using Akima spline interpolation (Akima, 1970), which preserves the smoothness and shape of the original time series without introducing oscillations.

Each turbine's power output was calculated by interpolating its discrete manufacturer-provided power curve P_{curve} allowing estimation of power outputs at intermediate wind speeds (Burton, Jenkins, Sharpe, & Bossanyi, 2011):

$$P_{\text{turbine}}(t) = f_{\text{interp}}\left(W_s(H, t)\right) \tag{4.29}$$

To realistically represent operational losses such as maintenance, wake effects, and inefficiencies, a random loss fraction L_{rand} between 10% and 30% was applied at each timestep, producing the net power output P_{net}.

$$P_{\text{net}}(t) = P_{\text{turbine}}(t) \times (1 - L_{\text{rand}}(t)) \tag{4.30}$$

The derived net power outputs were used to quantitatively assess the effects of different CfD scenarios, enabling detailed comparisons regarding dispatch distortions and revenue distributions among turbine technologies within OBZs.

4.4.3 Solution strategy and CfD implementation

The market clearing shows the scheduled flows and the price seen in each zone for each hour. The next part of the model includes a decision optimisation block for wind farms. This ensures the wind farms act upon the outcome of the market clearing based on the idea of revenue maximisation. It is assumed that the wind farm operators have complete information on the market clearing and the price dynamics in the market; hence, they can take an informed decision on the bid output.
Since this project focuses on the impact of different CfD schemes on the operational behaviour of wind farm operators, the optimisation equations depend on the CfD scheme being implemented. The decision of the wind farms depends on the best response to the price in the market and the CfD scheme. The decision of the wind farm is then relayed to the market which then clears the market again with the updated bids and fetches the new price for the offshore bidding zone. The wind farm optimises its output again and this process continues until the system converges to a maximum deflection of 0.1 €/MWh.

The offshore decision will be based on an optimal response strategy to the CfD scheme being implemented. The design of the CfD plays a crucial role in shaping these decisions. The CfD designs can be broadly categorised into two main types: production based or non-production based CfDs, as outlined in section 3. To assess the impact of different CfD designs, various case studies are formulated. These cases allow for a comparative analysis of different CfD structures, examining how they influence offshore wind farm operations and financial outcomes. The study evaluates the performance of each CfD design across multiple metrics, such as revenue stability, dispatch efficiency, and system integration. By analyzing these factors, the research aims to provide insights into the advantages and potential drawbacks of each design, ultimately helping to determine which CfD scheme best supports offshore wind development and grid stability.

4.4.4 Production Based CfD

This is dependant on the production of the generator, wherein payouts are offered based on the amount of power cleared and dispatched by the wind farm operator. The strike price for the CfD schemes is usually determined by a competitive bidding process, therefore the generators need to decide an optimal strike price to bid. In this model, the strike price is decided based on a rough estimate of the cost of running a wind farm levelised for an hourly price.

- **One-sided CfD model for Node n**

  Objective:

$$\max Rev_n^{OBZ} = \sum_{t \in T} \max\big(SP,\ \lambda_t^{\mathrm{OBZ}}\big)\ q_t^{\mathrm{OBZ},n} \tag{4.31}$$

  Constraint:

$$0 \ \leq\ q_t^{\mathrm{OBZ},n} \ \leq\ R_{n,t} \quad \forall t \in T \tag{4.32}$$

  The objective function is defined to calculate the maximum possible revenue from the market upon introduction of a one-sided CfD mechanism. This policy measure works on injection payments from the government to the wind farm operators whenever the spot price in the market is less than the strike price agreed for the CfD. The hours when the spot price exceeds the the strike price the wind farms are exposed to the market prices. The constraint 4.22 limits the wind farm from bidding more than it can produce in the hour.

- **Two-sided CfD model for Node n**

  Objective:

$$\max Rev_n^{OBZ} = \sum_{t \in T} (q_t^{\mathrm{OBZ},n} \cdot \lambda_t^{\mathrm{OBZ}} + q_t^{\mathrm{OBZ},n} \cdot (SP - \lambda_t^{\mathrm{OBZ}})) \tag{4.33}$$

The equation 4.23 is the objective function for implementing a two-sided CfD design in the OBZ, for maximising the revenue. A two-sided CfD has a clawback mechanism which includes a payment from the OWF generator to the government in the case of the spot price exceeding the CfD strike price. Remuneration is paid by the network operator to the OWF whenever the price falls below the agreed strike price. The constraint again being that the bid decided by the wind farm needs to be below the maximum possible output for the hour.

- **Cap and Floor CfD model for Node n**

$$\mathrm{Rev}_n^{\mathrm{OBZ}} = \sum_{t \in T} q_t \left(\lambda_t + \max\left(\mathrm{floor} - \lambda_t, 0\right) - \max\left(\lambda_t - \mathrm{cap}, 0\right)\right) \tag{4.34}$$

In this model a price cap and floor is defined through a bidding process and the wind farms see the market price if it is between the cap and the floor. For any price below the floor, the wind farms are given a renumeration equalling the difference between the floor and the market price times the volume output. Conversely, when the price exceeds, the cap the wind farms pay a clawback to the government.

4.4.5 Non-Production Based CfD

They are independant from the production by the wind farms, instead supplementing the generators with hourly payments. There is usually a reference wind farm whose output determines the clawback to the government. In the model different configurations of the reference generator are simulated to examine its impact on the behaviour of the wind farms. For the reference generator which will be separate from the wind farms at the nodes is decided to be judged using the wind profile that is seen in the wind farms and added noise to create a different dataset.

- **Financial CfD model for Node n**

S	Fixed hourly remuneration
$q_t^{\mathrm{OBZ},n}$	Asset production at node n in hour t
q_t^{ref}	Reference production in hour t

Objective:

$$\max Rev_n = \sum_{t \in Y} \left[S + \left(q_t^{\mathrm{OBZ},n} - q_t^{ref}\right) \cdot \lambda_t^{\mathrm{OBZ}}\right] \tag{4.35}$$

Hourly Revenue of Asset:

$$Rev_n(t) = S + q_t^{\mathrm{OBZ},n} \cdot \lambda_t^{\mathrm{OBZ}} \tag{4.36}$$

Hourly Cost of Asset:

$$C_n(t) = q_t^{ref} \cdot \lambda_t^{\mathrm{OBZ}} \tag{4.37}$$

The financial CfD model is independent of the generation of the OWF to provide a stable revenue for the wind farms. A fixed hourly remuneration is decided for the OWF based on a bidding process. Additionally, the wind farms also get revenue based on the power produced by the wind farm. The revenue is represented by the equation 4.24 for an hour t. The OWFs pay back an amount to the government, which is the clawback, based on the output of the reference wind farm. The overall revenue optimisation therefore, is shown in equation 4.24 summed up for all hours of the time series.

- **Capability based CfD model for Node n**

  This CfD model is similar in kind to the financial CfD model. The key difference is that the payment to the government is determined by the capability of the individual asset. This capability is linked to the individual estimation according to the weather data and asset specific parameters (ENTSO-E, 2024b).

SP	Strike price (€/MWh)
λ_t^{OBZ}	Hourly market reference price in the offshore bidding zone at time t (€/MWh)
$q_t^{\text{OBZ},n}$	Production potential (available power) of asset n in hour t (MW)
$\text{Rev}_n(t)$	Payment to asset n in hour t (€)

  Hourly Payment (Revenue) to Asset:

$$\text{Rev}_n(t) = q_t^{\text{OBZ},n} \cdot \lambda_t^{\text{OBZ}} + (SP - \lambda_t^{\text{OBZ}}) \cdot q_t^{\text{ref},n} \tag{4.38}$$

  The reference generator's output can be defined by Available Active Power (AAP)

- **Yardstick CfD model for Node n**

  This is another non production based CfD design proposed by David Newberry (D. Newbery, 2023). This CfD guarantees a payment to the OWF operators based on the difference between a strike price and the reference market price multiplied by the product of the wind farm capacity and the reference capacity factor. A factor containing the average difference between the actual generation at the site and the reference generator's output. This CfD design introduces a cap on the number of full load operating hours where the generators are paid.

SP	Strike price
λ_t^{OBZ}	Hourly spot price
$f_{r,i}$	Regional relative forecast generation in hour i
$f_{s,i}$	Bidding zone relative forecast generation in hour i
$f_{v,i}$	Asset relative metered output in hour i
K	Capacity of asset
H	Number of hours in one year

  Hourly Revenue of Asset:

$$Rev_n^{OBZ} = (SP - \lambda_t^{\text{OBZ}}) \cdot f_{r,i} \cdot K + a_i \cdot K \tag{4.39}$$

  Support Constraint:

$$\sum_{i=1}^{T} f_{v,i} = N \tag{4.40}$$

  Average Annual Deviation Adjustment:

$$a_i = \frac{\sum_{i=1}^{H} (f_{s,i} - f_{r,i}) \cdot \lambda_t^{\text{OBZ}}}{H} \tag{4.41}$$

  This model is more effective for larger locations where there is a significant impact of locational effects on the output of the wind farms. In this thesis, the OBZ is limited to an area where the weather data does not change significantly.

Other CfD models in literature that are non-production based CfDs are Yardstick CfDs and Capability CfDs. These CfDs however depend on the generation profile of the reference generator, therefore within the context of this model they boil down to the same thing. Therefore, additional cases of financial CfDs are considered to replicate a capability based CfD and yardstick CfD.

4.5 Evaluation Framework for CfD Schemes

To assess the effectiveness of different CfD designs, this section introduces a structured set of performance criteria. These indicators guide the evaluation of each case study, allowing for a comparative analysis of the outcomes under varying CfD structures.
The criteria are derived from policy guidelines, particularly the ENTSO-E Position Paper on CfDs (ENTSO-E, 2024b), and are aligned with the central objectives of this thesis—namely, to understand how CfD designs influence wind farm behaviour, revenue stability, and system-level efficiency.
Each CfD scheme is benchmarked against a reference case in which no support mechanism is applied. This reference case serves as a neutral baseline, enabling the identification of market distortions, inefficiencies, or behavioural shifts triggered by the implementation of specific CfD policies.
Table 4.4 summarises the core risk categories and metrics used to evaluate the performance of each CfD scheme. These are grouped into five key domains: price risk, volume risk, revenue risk, asset siting implications, and regulatory feasibility.

Risk Categories and Metrics	
Price risk	Standard deviation of prices (flat price risk)
	Frequency of non-intuitive prices (hours)
	Price collapse risk (number of hours near zero)
	Exposure to low-value power (hours below threshold)
	Exposure to high-value power (hours above threshold)
Volume risk	Total wind export (MWh)
	Capacity allocation inefficiency (hours curtailed)
	Capacity calculation inefficiency (MWh unallocated)
Asset siting	Impact on maintenance scheduling and plant availability
Revenue risk	Revenue variability (standard deviation, variance)
	Volume exposed to zero-price hours (MWh)
	Government clawbacks under two-sided or capped schemes (EUR)
Regulatory risk	Qualitative assessment of legal and policy feasibility

Table 4.4: Overview of CfD evaluation criteria used for cross-scenario comparison

4.5.1 Defining Volume Risks

The goal of the optimisation is to maximise the net export position of the OBZ across all time steps:

$$\max \sum_{t \in T} p_{\mathrm{OBZ},t} \tag{4.42}$$

where:

- $p_{z,t}$ is the net position (export or import) of zone z at time t,
- $\mathrm{OBZ} \in Z$ is the index of the offshore bidding zone.

Decision Variables

- $p[z,t]$: Zonal net position for each zone $z \in Z$ at time t
- $p_{\mathrm{FB}}[z,t]$: Flow-based net position excluding DC effects
- $F_{\mathrm{FBMC}}[l,t]$: Commercial flow over AC lines
- $F_{\mathrm{DC}}[l,t]$: Commercial flow over DC links

Constraints

The model includes the following constraints to ensure feasibility of power flow:

1. Zonal Balance:

$$\sum_{z \in Z} p[z,t] = 0 \quad \forall t \in T \tag{4.43}$$

2. Zonal Flow Conservation:

$$\sum_{l \in L} F_{\mathrm{FBMC}}[l,t] \cdot i[l,z] + \sum_{l_{\mathrm{DC}} \in L_{\mathrm{DC}}} F_{\mathrm{DC}}[l_{\mathrm{DC}},t] \cdot i_{\mathrm{DC}}[l_{\mathrm{DC}},z] = p[z,t] \quad \forall z,t \tag{4.44}$$

3. Flow-Based Position Adjustment:

$$p_{\mathrm{FB}}[z,t] = p[z,t] - \sum_{l_{\mathrm{DC}}} F_{\mathrm{DC}}[l_{\mathrm{DC}},t] \cdot i_{\mathrm{DC}}[l_{\mathrm{DC}},z] \tag{4.45}$$

4. Flow Constraints on AC Lines (RAM Limits):

$$-\mathrm{RAM}_{\mathrm{neg}}[l,t] \leq \mathrm{F}_{\mathrm{FBMC}}[l,t] \leq \mathrm{RAM}_{\mathrm{pos}}[l,t] \quad \forall l,t \tag{4.46}$$

5. Flow Constraints on DC Lines (NTC Limits):

$$-\mathrm{NTC}_l \leq F_{\mathrm{DC}}[l,t] \leq \mathrm{NTC}_l \quad \forall l \in L_{\mathrm{DC}}, t \tag{4.47}$$

This result represents the maximum net export position of the OBZ at each timestep $t \in T$, while ensuring full feasibility for the grid's AC and DC power flow constraints.

Volume Risk Categories

Following the calculation of export potential, volume risk is evaluated by comparing this maximum feasible export to the available renewable generation and the actual dispatched power. Three types of risk are defined:

1. Capacity Calculation Risk This risk occurs when the OBZ's export potential exceeds the capacity allocated by the flow-based domain, even though the wind farms were technically able to generate more. This reflects an overly conservative grid domain calculation.

$$\text{If} \quad \mathrm{PotentialRES}_t > \mathrm{maxposOBZ}_t \geq \mathrm{ActualRES}_t, \tag{4.48}$$

$$CCR_t = \mathrm{PotentialRES}_t - \mathrm{maxposOBZ}_t \tag{4.49}$$

2. Capacity Allocation Risk This occurs when the capacity to export is available, but curtailment still takes place. This may result from inefficient market dispatch or internal congestion not resolved in market clearing.

$$\text{If} \quad \text{maxposOBZ}_t \geq \text{PotentialRES}_t \quad \text{and} \quad \text{Curtailment}_t > 0, \tag{4.50}$$

$$CAR_t = \text{Curtailment}_t \tag{4.51}$$

3. Combined Risk Case In some hours, both types of risk may be present simultaneously—export capacity is underestimated, and the actual dispatch is curtailed below the potential. In such cases, both loss components are captured:

$$\text{If} \quad \text{maxposOBZ}_t < \text{PotentialRES}_t \quad \text{and} \quad \text{maxposOBZ}_t < \text{ActualRES}_t, \tag{4.52}$$

$$CCR_t = \text{PotentialRES}_t - \text{maxposOBZ}_t \tag{4.53}$$

$$CAR_t = \text{Curtailment}_t - CCR_t \tag{4.54}$$

These metrics form the basis for quantifying volume risk across CfD scenarios, and are used later to compare curtailment outcomes and transmission inefficiencies.

4.5.2 Defining Price risks

Price risk is evaluated using both intra-zonal and inter-zonal indicators, as well as relative alignment between the offshore bidding zone (OBZ) and neighbouring market zones.

Intra-Zone Indicators

For each zone, the following indicators are computed:

- **Average Price:** The mean electricity price over all hours in the year.
- **Standard Deviation:** Measures the hourly price volatility within the zone.
- **Coefficient of Variation (CV):** The standard deviation normalised by the mean price, used to compare variability across zones with different price levels.

These indicators reflect the level and volatility of prices that each offshore wind farm may be exposed to, depending on its location.

Inter-Zone Indicators

Inter-zonal metrics aggregate average price values across all zones to assess spatial dispersion:

- **Inter-Zone Mean:** The average of zonal mean prices.
- **Inter-Zone Standard Deviation:** Measures how spread out the zonal mean prices are.
- **Inter-Zone Coefficient of Variation:** Indicates relative variability in mean prices between zones.

Relative Price Alignment (OBZ Comparison)

Each hour is classified based on how the OBZ price compares with the three neighbouring nodes:

- **Lowest Price:** When the OBZ matches the lowest of the three zonal prices.
- **Middle Price:** When the OBZ matches one of the middle values in a non-uniform price setting.
- **Highest Price:** When the OBZ matches the highest zonal price.
- **Non-Intuitive Price:** When the OBZ price does not match any of the three neighbouring zones.

Furthermore, price delta analysis is used to identify hours where the actual realised price differs from the initial bid price submitted by the offshore wind farm. This reflects the exposure to settlement price mismatches caused by grid constraints or bidding behaviour.

4.5.3 Social Welfare Evaluation

The primary objective of this analysis is to evaluate the economic efficiency of various CfD policies by examining their impact on social welfare. By comparing each alternative against the baseline, it is possible to identify net economic gains or losses from shifts in welfare components.
In evaluating the welfare implications of different market configurations, this thesis adopts a classical economic definition of social welfare as the sum of consumer surplus and producer surplus and a deduction of system costs (Kirschen & Strbac, 2004). Social welfare is maximised when the market allocates resources such that the marginal benefit equals the marginal cost. Therefore, in this analysis, changes in system costs, such as additional generation costs due to inefficient dispatch or price changes due to policy, are explicitly deducted from the change in producer profits to estimate the net change in welfare.

$$\Delta SW = \Delta\Pi^{\text{producer}} + \Delta CS - \Delta C^{\text{system}} \tag{4.55}$$

ΔSW is the change in social welfare,

$\Delta\Pi^{\text{producer}}$ is the change in producer profit,

ΔCS is the change in consumer surplus,

ΔC^{system} is the change in total system cost.

In the cases involving financial support mechanisms like CfDs, the fixed payments received by offshore wind farms from the government are directly included in the revenue streams of producers. Accordingly, these payments are captured in the $\Delta ProducerProfit$ term. While such payments do affect government budget balance, they represent a transfer rather than a real economic cost, consistent with welfare accounting practices in the energy economics literature (Pollitt, 2012) (D. Newbery, 2016). Hence, the model considers the fixed payments to be part of producer surplus and does not treat them as an external system cost in the welfare balance.

4.6 Model Validation

The market clearing is solved based on a model developed by (Kenis et al., 2023) and (Verkooijen, 2024), whose report validates the FBMC model and is extended in this study. To ensure the model functions correctly, the inclusion of the OWF decision must be tested. This is done by running a case without any CfD support structures. In theory, the results should match those of a model without the wind farm decision block. This is because, without a CfD or other policy intervention, the wind farm responds only to market-clearing prices. Since there is no incentive to adjust its bids, it continues to offer its maximum production potential. If the results align, it confirms that the model behaves as expected.

One of the key cases analyzed is when the offshore wind farm must make bidding decisions without any CfD support. In this scenario, the wind farms respond purely to market prices without any financial intervention. The results show that wind farms consistently bid their maximum available capacity. This outcome aligns with expectations since, in the absence of financial incentives, there is no reason for the wind farms to adjust their bids based on economic considerations.

Curtailment in this case occurs systematically due to two main factors: congestion on the HVDC transmission lines and excessive wind energy production exceeding demand. Since the offshore decision block does not introduce any new bidding behaviour under these conditions, the overall market clearing results remain unchanged. The position of the OBZ and the price formation within the zone are identical to those observed in the base model without the offshore decision component. This consistency confirms that the model behaves as expected when no CfD mechanism is present.

To further validate the model, a second case is analyzed where a one-sided CfD scheme is introduced. Under this scheme, the offshore wind farm operators receive a payment covering the difference between the market spot price and a predefined strike price whenever they generate electricity. This creates a strong financial incentive for wind farms to produce at maximum capacity, regardless of market prices.

In theory, wind farms under a one-sided CfD scheme will continue to generate power as long as the spot price remains below the strike price. This is because they are guaranteed a payment from the government equal to the difference between the strike price and the spot price, multiplied by the volume of electricity produced. When the spot price exceeds the strike price, there is no clawback since it is a one-sided CfD, so the generators will be exposed to the market price.

The model successfully replicates this expected behavior. The wind farm consistently bids at its maximum available power output to maximise its revenue under the CfD scheme. As a result, the total volume of wind energy output in the market clearing remains unchanged compared to the case without a CfD. Additionally, the position of the wind farm and the power flows in the transmission lines connected to it remain the same.
This validates the design of the model as the logical hypothesis is upheld by the cases simulated in the model.

5 | Case Study

This chapter explores the baseline model setup and consequently sets up the scenarios and cases within the scenarios to be analysed. Section 5.1 examines the topology of the grid and the baseline data of the generators and demand used at the CNEs. The following section 5.2 lists the cases to be investigated within each scenario. These cases are determined from the literature on CfDs reviewed in Chapter 3. Lastly, Section 5.3 introduces the scenario framework for the OBZ, capturing different operating conditions to evaluate wind farm behaviour under various CfD designs.

5.1 Model Setup

The model is based on the work of (Kenis et al., 2023), which represents an onshore grid network with three onshore bidding zones and one OBZ. The model includes both AC and DC transmission lines, requiring the application of AHC to solve the system, as discussed in Section 2.2. The power system underlying this study incorporates both renewable and conventional energy sources, along with a fixed demand for each bidding zone. There are six offshore wind farms, each with a capacity of 500 MW. Three of these wind farms operate under a HM setup, each connected directly to a separate onshore bidding zone, while the remaining three collectively form the OBZ.

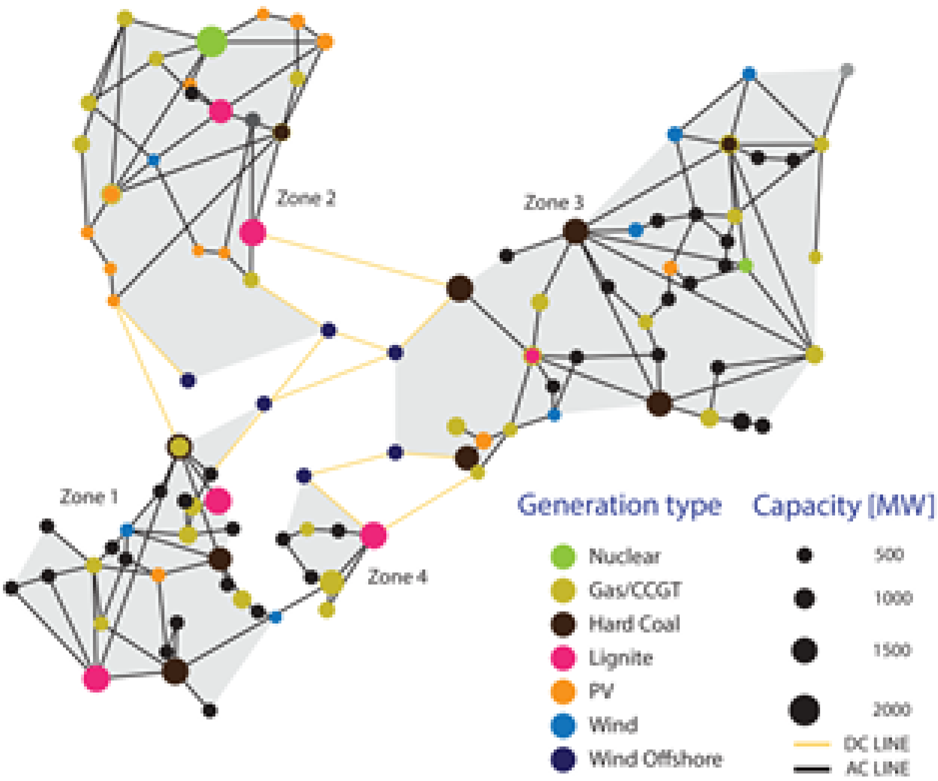


Figure 5.1: Grid Topology
(Kenis et al., 2023)

The network consists of 103 nodes and 237 AC lines connecting different nodes. 3 nodes make up the offshore bidding zones, which are connected to each other and to the onshore bidding zones by DC lines, totalling 12. The grid consists of three onshore bidding zones and an offshore bidding zone. Some of the nodes contain CNEs, which are represented by loads and generators. In the model, the offshore bidding zone (OBZ) comprises three nodes, each hosting an offshore wind farm. As intra-zonal HVDC lines are not visible in the market clearing and no internal congestion is modelled, the OBZ is treated as a single virtual hub. This simplification reflects copper-plate behaviour within the OBZ, allowing the three OWFs to be considered as a single aggregated generation setup.
There are 7 types of generation consisting of Nuclear, Gas/CCGT, Hard Coal, Lignite, PV, Wind and Offshore wind. Each generator has a different capacity. The model is derived from (Schönheit et al., 2021), and the hourly data is used as is from the model. The hourly weather data from Belgium, France and Germany from 2015 is used for zones 1-3 of the year 2015 from SETIS (González Aparicio & Huld, 2017). The OBZ wind is determined from the average capacity factors of the three zones. The load values are determined based on the node-specific time series by (Schönheit et al., 2021) made to fit within the topology of the grid. Perfectly inelastic demand is assumed for the purpose of this study and the weather data is left unchanged.
The network has been designed by (Schönheit et al., 2021) and implemented by (Kenis et al., 2023). It is composed of multiple zones and nodes, with each node hosting different power plants of varying capacities, all interconnected by transmission lines. These lines are subject to a thermal constraint that limits the amount of power they can carry. The DC lines in the OBZ can carry a maximum of 1000 MW and have an average capacity of 833 MW. The model also includes a flexible offshore demand agent in the form of an electrolyser, which operates based on grid conditions and has a defined willingness to pay.

The NTC value is set at 100%, which means that all of the DC interconnector capacity is made available for market clearing. As mentioned earlier, the MinRAM capacity is set at 70%, making at least 70% of the capacity available for cross-border interconnection. The curtailment cost is set to 0 €/MWh, which means that there is no payment from the TSO to the OWF whenever there is curtailment required by the wind farm.

5.2 Offshore Wind Turbine Technology

There are different wind turbine technologies used offshore, each with different characteristics. (Chirosca, Rusu, & Bleoju, 2022) lists different wind turbine technologies used for offshore projects in the North Sea. From the different turbine technologies listed, Vestas V112, Vestas V80 and Vestas V164 are selected for closer inspection in this project.
To investigate whether the implementation of CfDs introduces any dispatch bias towards specific turbine technologies, a comparative analysis of hourly power production profiles was conducted. Figure 5.2 presents an illustrative snapshot comparing the power output profiles of three selected offshore wind turbines: Vestas V164, Vestas V80, and Vestas V112, under identical wind conditions.

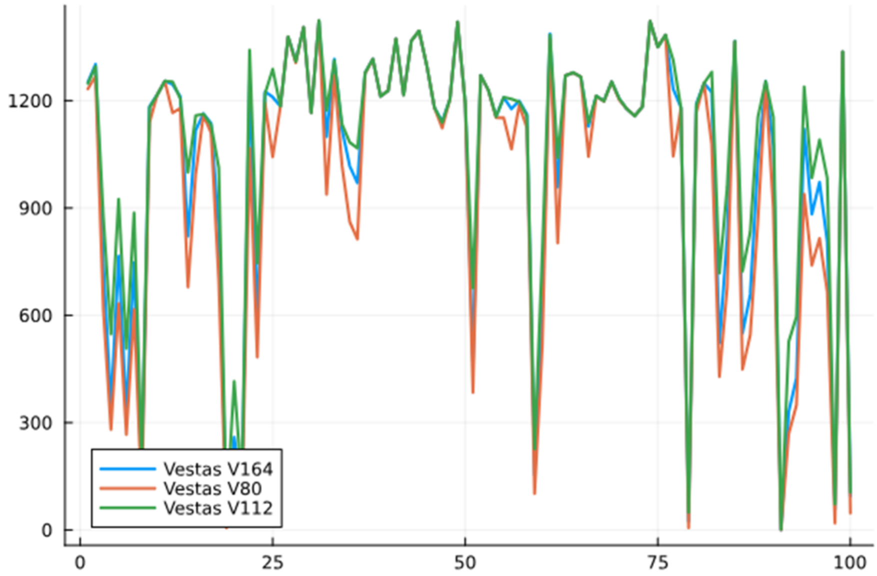


Figure 5.2: Comparison of hourly power production profiles for selected offshore wind turbine technologies (Vestas V164, V80, and V112).

The observed differences in the power generation profiles highlight how each turbine's power curve influences the actual power output. Notably, the Vestas V112 consistently produces slightly higher outputs during medium wind speed conditions, whereas the Vestas V80 experiences more variability and lower outputs at similar intervals, reflecting its lower-rated power and narrower operational range. The Vestas V164 demonstrates a stable and relatively consistent power output due to its higher-rated capacity and optimised power curve design for offshore conditions.

Assessing such differences is critical for understanding if certain CfD structures implicitly favour particular turbine technologies due to their distinct response under variable wind conditions. Any systematic bias uncovered could significantly influence future technology deployment and investment strategies within OBZs.

5.2.1 Reference Case

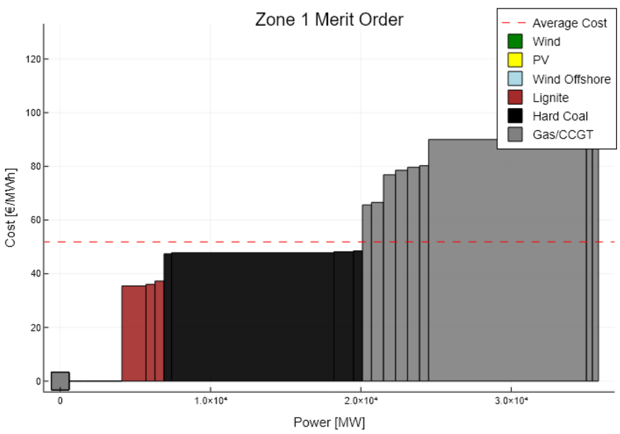
This is the case without any CfD being applied to estimate the price formation in the OBZ. The output from the market clearing will illustrate some of the obstacles in the implementation of OBZs and will prompt the need for policy intervention in the form of CfDs.

The generation mix is an important input for the model. This thesis impresses on the integration on OWF in an OBZ system, which implies a high share of renewables in the system. Therefore, the generation data for the model has been derived from the *"very high vRES case"* from (Schönheit et al., 2021). The generation mix consists of a mix of renewable and non-renewable sources, which are dispatched based on a merit order with the generator with the least variable costs being dispatched first.

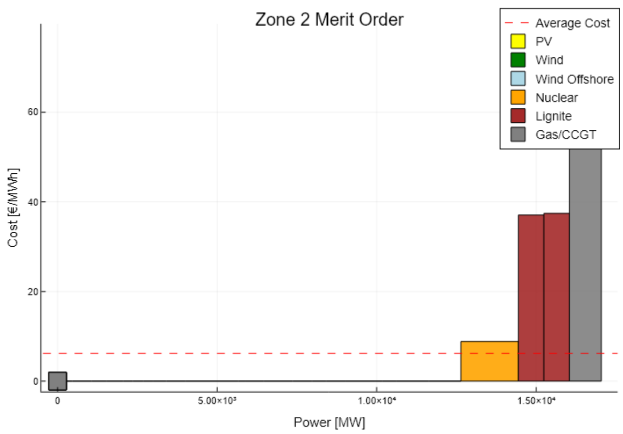
There is more generation compared to the maximum demand requirement due to there being a high percentage of renewables in the mix. The variable cost of PV and wind energy is 0 € /MWh, therefore, they are highest in the merit order. The generators with higher variable costs are termed as marginal generators and are deployed when there is an underproduction of wind or PV energy or due to grid constraints.

The OBZ has a triangular setup with an OWF at each node, and each node is connected to the onshore zones and the other nodes within the OBZ with an HVDC connection. The capacity limit of

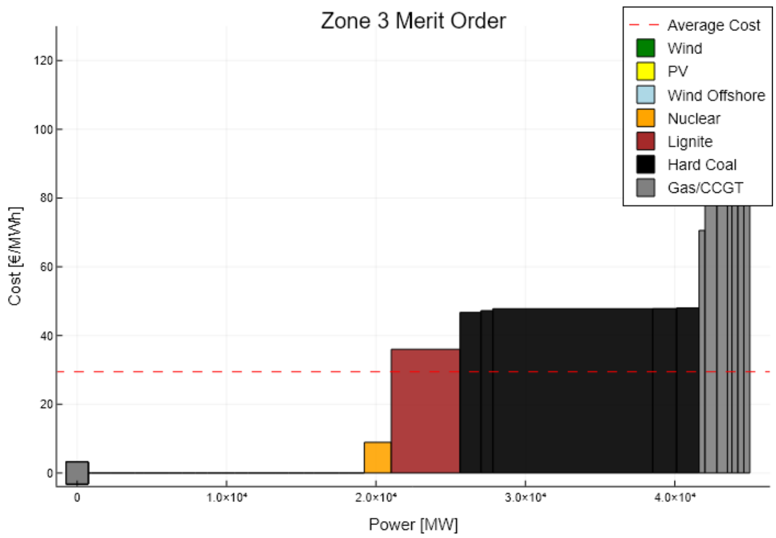
the HVDC lines is 800, 1000 and 500 MW to the corresponding onshore zones. The landing points on the onshore AC grid should be sufficiently sized to be able to incorporate the power generated from the OWF. If the OWFs are overdesigned, it leads to inefficient utilisation of power due to curtailment. The OWF sizing in this thesis is based on the approach by (Verkooijen, 2024), where the maximum and average net export positions of the OBZ were evaluated to ensure technical feasibility. First, an optimisation was performed considering only physical grid constraints, which yielded a maximum average net export potential of approximately 5715 MW. Then, a second optimisation including FBMC constraints—representing actual market-clearing limitations—showed a reduced average net position of 4629 MW.
Based on these results, the OWF capacities were selected to ensure that their combined generation does not exceed the OBZ's typical export capability under market conditions. A total OWF capacity of 4.5 GW (1.5 GW per wind farm across three OWFs) was chosen to align with the average net position while avoiding frequent curtailment or infeasibility.



(a) Zone 1



(b) Zone 2



(c) Zone 3

Figure 5.3: Generator merit order for the first three zones.

The image above shows the different generation technologies arranged in ascending order according to their variable costs. The first zone consists largely of traditional generation sources, including Gas CCGT, hard coal and lignite, which explains the higher average variable costs of producing power in the zone. Zone 2 has a higher renewable share in its mix, shown by the initial gap in the x-axis, because of the zero variable costs of generator technologies like PV and wind. Similarly, zone 3 has a high share of renewable energy, amounting to almost half of all the generation. Zone 4 is the OBZ, consisting of three offshore wind farms; therefore, the variable cost of power production in this zone is zero.

5.3 Case Study

The cases are formed based on the CfD schemes discussed in the literature, and they are studied based on the different metrics mentioned in the methodology. The cases are branched under production based CfDs and non-production based CfDs. The cases under production based CfDs are One-Sided CfD (Case 1), Two-sided CfD (Case 2), Cap and floor CfD (Case 3) and non production based CfDs contain Financial CfD (Case 4). The reason for implementation of each case is enumerated and the hypothesis of the expected outcome of the specific cases is described.

5.3.1 Case 1: One-sided CfD

The first case group is aimed at modelling a one-sided CfD, which offers support to the OWF operators in the period of lower prices. The strike prices for any CfD policy are determined through a competitive bidding process wherein the OWF operator agrees upon a price which will best suit their operation. The strike prices are usually determined with a projection of the prices and the Levelised Cost of Electricity (LCOE) for the wind farms. However, this is not a point of focus in this thesis.

5.3.2 Case 2: Two-sided CfD

The second case group consists of the two sided CfD policy. The strike price for this policy is determined via a bidding process, which is not calculated in the thesis. Different strike prices for the policy are analysed to the trends in the bidding process by the wind farm operators.

Within this case, 2 subcases are studied. The first case is where the market price received by the generators is fixed for each hour and is the reference market price. The generators, therefore, have no incentive to change their bidding behaviour as they will aim to maximise production. There is no response to zero or negative prices, however, a condition has been added to not produce energy when there are negative prices. This case will show if the hypothesis about the behaviour under this policy is as expected and the results from this case can be further dissected to observe inefficiencies being triggered due to the implementation of production-based CfDs.

The second subcase within this case is where a yearly averaged reference price is used for studying the implications of the policy. Having a yearly average price exposes the wind farms to the daily price fluctuations, which makes the wind farms more adept at adapting to the price signals. In this CfD design, the OWF operators are aware before the DA market whether they will be receiving a payment or will be paying the government. This can therefore lead to dispatch distortions wherein the wind farms alter their bid by inflating the bid price at a higher price than the variable cost. This cannot be captured in the thesis as the wind farms can change the volume bid, but not the price at which the power is offered.

5.3.3 Case 3: Price Cap and Floor CfD

The next case is where a cap and floor CfD scheme wherein a minimum and maximum payment is guaranteed for the OWF generators. The floor value is generally lower than the strike price of a two-sided CfD. The generator is exposed to the market prices whenever the spot prices are between the floor and the cap value of the policy.

Like the two-sided CfD, the floor price for the cap and floor CfD is decided through competitive bidding between the OWF generators.

5.3.4 Case 4: Financial CfD

The next case falls under the non production based CfD design. The objective of the policy is to decouple the payments from the production of power. The payment to the wind farms is tied to a benchmark reference generator instead of the asset itself.
The first case is to have an average output of the three locations as the reference profile. This design for the reference profile has been proposed by (Schlecht et al., 2024) Subsequently, the second case considers different nodes for the reference output. There are three subcases within this case, as there are OWFs in the OBZ. An important consideration here is that the wind farms in the OBZ are situated in close proximity of each other, therefore have similar wind conditions.

In the third and fourth cases, two and one wind farms, respectively, are exposed to financial CfDs, while the remaining wind farms bid according to market prices. Similarly, there are three subcases within each of these cases.

5.4 Scenario Definitions

Three axes of freedom are varied along with these different cases to analyse how each impacts the different CfD designs. The first degree of freedom explores the temporal alignment of wind power production between OWFs. While the default setup assumes that the OWFs are co-located and therefore experience similar wind conditions and output profiles. This assumption is relaxed to mimic the effect of geographic separation. By shifting the wind power time series of one or more OWFs by 10 time steps (e.g., 10 hours), the model introduces artificial variation in generation timing across the OWFs. This approach allows the analysis to approximate the impact of spatially dispersed wind farms that experience different wind conditions.

The second degree of freedom pertains to the turbine technology chosen for the OWFs. The default scenario assumes that all OWFs employ the same technology, which is then modified to incorporate one or more distinct turbine technologies. Any biases that emerge in favour of a particular technology will be evident in this study.

The final degree of freedom concerns the presence of a demand agent within the OBZ. The objective is to determine whether the existence or absence of this agent influences the design of the CfD and the subsequent bidding behaviour of the OWFs. These degrees of freedom are adjusted within the framework of the outlined cases for thorough analysis. The cases mentioned above are studied for each of the defined scenarios.

5.4.1 Scenario 1: Aligned Wind, Same Turbine Technology, No Off- shore Electrolyser

This is the baseline scenario where all offshore wind farms experience identical wind profiles and employ the same turbine technology. No offshore demand agent is present in this configuration.

Purpose:
This scenario provides a reference case with minimal structural asymmetries. It allows for a comparison of different CfD mechanisms without the influence of temporal, technological heterogeneity or the presence of an offshore electrolyser. This helps isolate the intrinsic design effects of each CfD on generator behaviour.

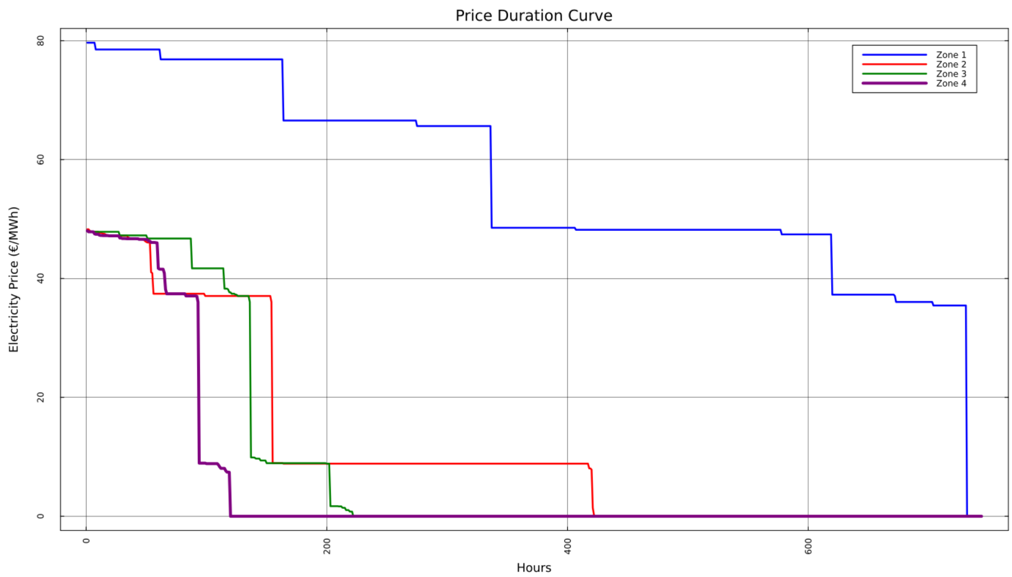


Figure 5.4: Price duration curve for Scenario 1 without a CfD

The price duration curve shows that the OBZ experiences zero prices more than 75% of the time. This reflects the high share of offshore wind and zero marginal cost generation. In contrast, Zone 1, dominated by traditional thermal sources like coal and gas, maintains significantly higher prices due to higher operating costs. The system-wide high renewable penetration leads to a clear trend of prolonged low or zero price periods, highlighting the challenges of market value under high VRE conditions.

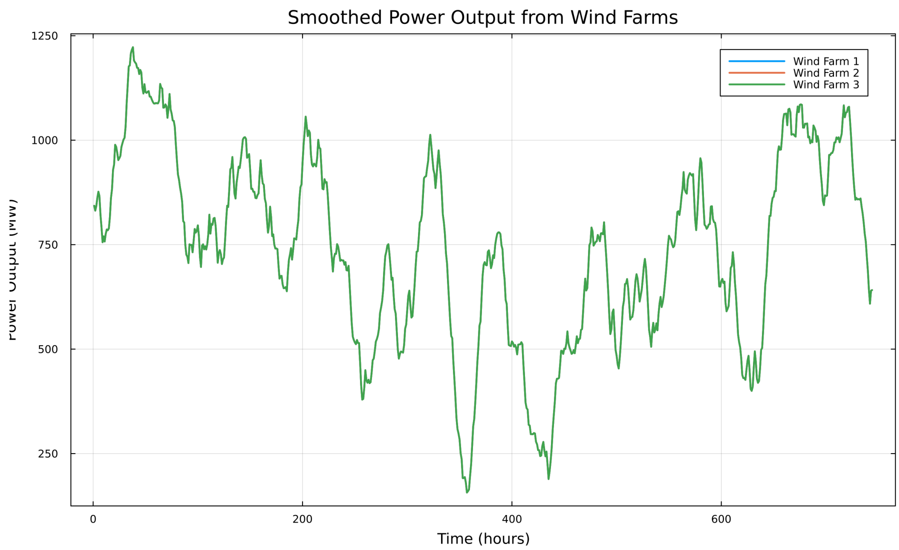


Figure 5.5: Power output of OWFs in Scenario 1: Aligned wind profiles, same turbine technology, no offshore electrolyser

This plot shows similar power patterns from all OWFs, as they experience the same wind conditions.

5.4.2 Scenario 2: Misaligned Wind, Same Turbine Technology, No Offshore Electrolyser

To simulate real world variability in weather patterns, this scenario introduces a temporal shift in wind profiles across the offshore wind farms. Each OWF still uses the same turbine technology, and no demand agent is included.

Purpose:
This scenario evaluates how CfDs perform when production is not perfectly synchronised across sites. It is especially relevant for non-production-based CfDs, where reference profiles may not accurately reflect individual asset output.
The objective of this analysis is to evaluate how different real-world configurations of offshore wind deployment influence the performance of various CfD mechanisms. By introducing variations in wind production timing, turbine technologies, and flexible demand presence, the study simulates varied operational conditions. This framework allows for an assessment of how the impact of CfDs may shift depending on the characteristics of offshore wind systems.
Each OWF now has a shifted wind profile, leading to visible differences in power output.

5.4.3 Scenario 3: Aligned Wind, Different Turbine Technology, No Offshore Electrolyser

Here, the OWFs experience the same wind conditions, but each employs a different turbine type (e.g., Vestas V80, V112, V164), resulting in different power output characteristics due to variation in rated power, cut-in speeds, and efficiency curves.

Purpose:
This scenario probes the sensitivity of CfD designs to technology selection. It is used to identify whether particular turbine types are implicitly favoured or disadvantaged by the structure of the CfD, especially under benchmarked remuneration schemes. The results offer insights into technology distortions and investment incentives.

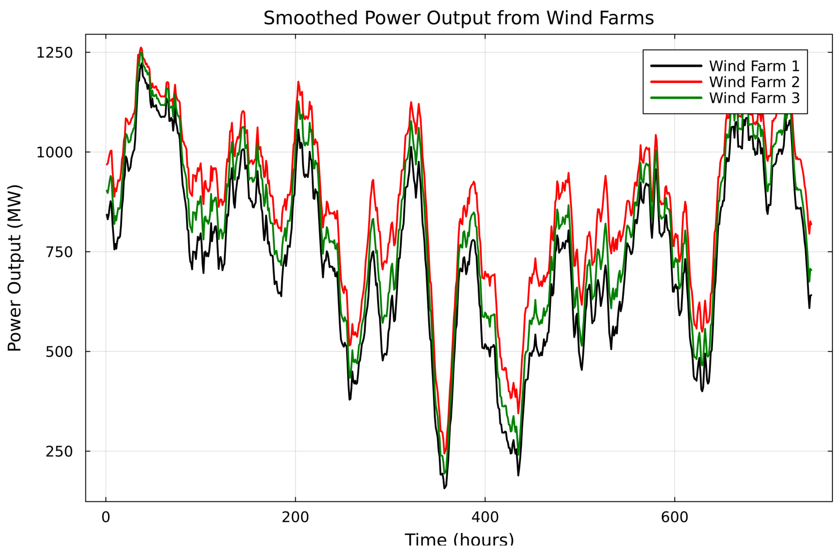


Figure 5.6: Power output of OWFs in Scenario 3: Aligned wind profiles, different turbine technologies, no offshore electrolyser

Even with the same wind, the OWFs show different outputs due to their turbine technologies.

5.4.4 Scenario 4: Scenario 4: Misaligned Wind, Different Turbine Technology, No Offshore Electrolyser

This scenario introduces both temporal misalignment and technological diversity, representing a highly realistic but complex operational condition in the OBZ. All wind farms have unique power curves and operate under shifted wind profiles.

Purpose:
The goal is to test the robustness and fairness of CfD schemes under the most realistic offshore system setup. This scenario is expected to highlight the combined effects of locational and technological basis risk and reveal if some CfD designs are resilient or disproportionately distortive under real-world heterogeneity.

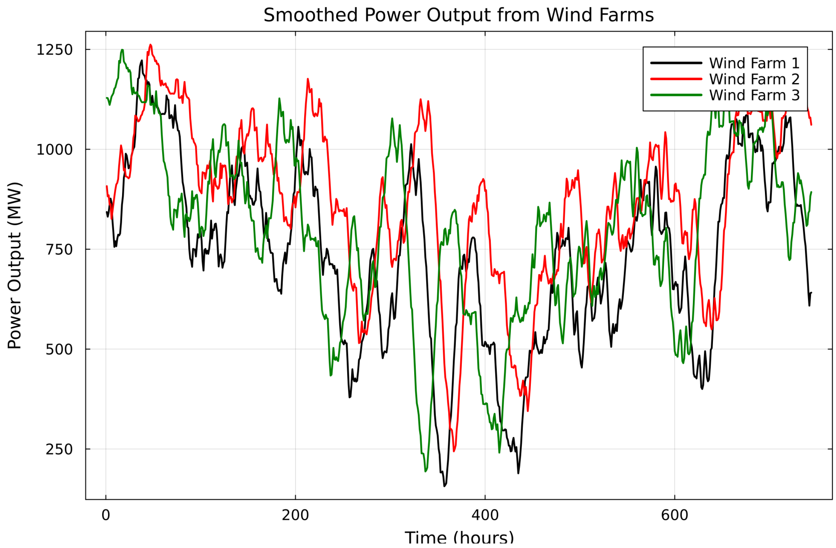


Figure 5.7: Power output of OWFs in Scenario 4: Misaligned wind profiles, different turbine technologies, no offshore electrolyser

This scenario combines different wind profiles and turbine types, creating the most variation.

5.4.5 Scenario 5: Aligned Wind, Same Turbine Technology, Offshore Electrolyser on a node

The last scenario returns to the symmetric baseline configuration. This scenario introduces a flexible demand agent in the OBZ—an electrolyser load connected to one offshore node.

Purpose:
This scenario explores the interaction between CfD schemes and flexible demand agents. The electrolyser can respond to market prices, potentially absorbing excess supply or easing congestion. It is used to study whether CfDs encourage or suppress efficient use of flexible demand, and whether dispatch behaviour changes in their presence.

Scenario	Wind Profile Alignment	Turbine Technology	Offshore Electrolyser
Scenario 1	Aligned	Same	No
Scenario 2	Misaligned	Same	No
Scenario 3	Aligned	Different	No
Scenario 4	Misaligned	Different	No
Scenario 5	Aligned	Same	Yes

Table 5.1: Summary of Scenario Configurations

5.5 Chapter overview

This chapter outlined the model configuration and described the design of case studies used to evaluate different CfD schemes. It began by introducing the grid topology and offshore wind turbine technologies implemented in the OBZ. Four main CfD designs—three production-based and one non-production-based—were presented, each with specific variations to test their operational and financial impact. These cases were assessed under five distinct scenarios, varying wind alignment, turbine technology, and offshore demand presence. This setup enables a systematic evaluation of how CfD design interacts with offshore system characteristics, providing the foundation for the results and discussion in the following chapters.

6 | Results

This chapter presents the findings of the simulations conducted for the different scenarios presented in the previous section. Each scenario varies in its assumptions regarding wind profiles, turbine technology, CfD coverage, and the presence of an offshore electrolyser. The results of every scenario are evaluated against its corresponding reference case, defined as the market-clearing outcome in the absence of any policy intervention. Section 6.1 provides a closer examination of the various cases, highlighting some recurring patterns observed across the scenarios. Sections 6.2 to 6.5 present the results from each of the remaining four scenarios, drawing attention to key findings unique to each one. Finally, Section 6.6 offers a comparative overview of all scenarios. This includes a cross-scenario analysis to identify the key effects each setup has on the evaluated performance metrics.

To ensure clarity, the results are organised to explain three key analytical themes:

- **Price Risks:**
  Examining price formation, average price levels, the occurrence of non-intuitive prices, and how different CfD mechanisms address these risks.
- **Volume Risks:**
  Evaluating the extent of curtailment and identifying capacity calculation and allocation risks across the scenarios.
- **Bidding Behaviour and Revenue Outcomes:**
  Analysing how OWFs respond to different CfD designs, how revenues are distributed across wind farms, and how the selection of the reference generator affects both bidding behaviour and the revenue.

6.1 Scenario 1: Aligned Wind, Same Turbine Technology, No Offshore Electrolyser

This scenario serves as the baseline for analysing the impact of CfD policies under idealised conditions. This scenario has all the offshore wind farms using the same technology and experiencing the same wind conditions. The wind speeds are perfectly aligned, meaning that the production profiles of the wind farms are temporally identical. Additionally, there is no offshore hydrogen electrolyser, therefore, the entire offshore generation must be either transmitted to the onshore grid or curtailed. The objective is to isolate the effects of the CfD structures on the market outcomes, pricing behaviour and system congestion.

The scenario is analysed across multiple CfD configurations, each of which is tested against a common reference case without policy support. The results obtained are then organised according to the three categories: price risks, volume risks and bidding behaviour with revenue outcomes. This case reveals key behavioural baselines, including systemic price collapse under production-based CfDs, the emergence of strategic curtailment and revenue equalisation under financial CfD designs. These results are used to contextualise later scenarios.

This scenario is studied in detail using the different cases mentioned in the previous section. The aim is to optimise the wind farm decision based on the selected case and represent the results. The metrics to gauge the results are broadly grouped under three categories: price risks, volume risks and general characteristics.

6.1.1 Price Metrics

The PDC in figure 5.4 for the reference scenario offers a complementary perspective, illustrating the number of hours each bidding zone experienced specific price levels. Zone 4, the OBZ, exhibits a flat curve at 0 €/MWh for the vast majority of the year, reaffirming that prices were virtually nil throughout under the baseline market conditions. This observation underscores the need for the implementation of policy to support the development of wind in the OBZs. The grid is designed to show a high penetration of renewables in the system. Zones 2 and 3 have high wind and PV systems, while Zone 1 relies more on expensive non-renewable power, hence having the highest prices.
This section investigates how various CfD configurations affect price formation and bidding dynamics in the OBZ. Each configuration is compared against this reference case to isolate the effects of contractual structure on price behaviour. Three key mechanisms are observed:

- Under no policy or production-based CfDs, OWFs bid full capacity, leading to congestion and systemic price collapse.
- Under financial CfDs, OWFs strategically reduce output to align with reference generators, leading to price dispersion and stabilisation.
- Under asymmetric CfD coverage, behavioural divergence between contracted and uncontracted OWFs causes erratic and non-intuitive price outcomes.

Overview of metrics and CfD impact

Table 6.1: Price risk metrics under Aligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Mean price (€/MWh)	5.76	6.61	6.61	6.61	6.61	6.54
Std Dev	14.51	14.39	14.39	14.39	14.39	14.45
Variance	2.52	2.18	2.18	2.18	2.18	2.21
Low price hours (h)	603	655	655	655	655	623
– Zero price (h)	523	523	523	523	523	523
– Non-zero price (h)	80	132	132	132	132	100
Medium price hours (h)	3	2	2	2	2	3
High price hours (h)	0	0	0	0	0	0
Non-intuitive price (h)	138	87	87	87	87	118
– Zero price (h)	102	28	28	28	28	34
– Non-zero price (h)	36	59	59	59	59	84
Price delta (bids) (h)	0	75	75	75	75	68

Table 6.1 presents key price metrics under different CfD configurations for Scenario 1. Under production-based 2-sided CfD, prices in the OBZ collapse to 0 €/MWh in 567 hours, corresponding to 76.2% of the simulation period. The resulting average price is the lowest out of all the cases studied, with 5.76 €/MWh and the highest volatility (standard deviation of 14.51). It is observed that the metrics in production-based CfDs are the same as those without any CfD design.

In contrast, all financial CfD variants lead to modest price increases (up to 6.61 €/MWh), with lower variance and fewer instances of non-intuitive prices, dropping from 173 under the production-based scheme to 87. Notably, the metric "price delta (bids)" is non-zero only under financial CfDs, indicating strategic volume adjustments by OWFs in response to reference generator output. These results suggest that while financial CfDs improve price stability and reduce market anomalies, they introduce new dynamics linked to their bidding behaviour.

The following subsections provide a detailed analysis of the price-related metrics presented in Table 6.1, offering insights into the underlying dynamics observed in Scenario 1.

The frequency of key dispatch-related events across the simulation period is summarised for three policy setups: the Market-Only case (no CfD), the Uniform CfD case (financial CfD applied equally to all wind farms with an average-based reference), and the Hybrid CfD case (CfD applied to two wind farms, with one exposed to the market).

Key insights from Table 6.1:

- Production-based CfD replicates the reference case with 0 €/MWh prices in 523 hours.
- Financial CfDs raise average prices modestly and reduce price volatility.
- Strategic adjustments emerge only under financial CfDs
- Hybrid CfDs exhibit the most non-zero, non-intuitive price events (84 hours), due to diverging incentives.

Distribution and severity of price risks

This section shows how the price metrics mentioned above impact the system and what the key takeaways from these price metrics are. The figures and facts mentioned below will help to make inferences about the behaviour of the OBZ under CfD policy designs.

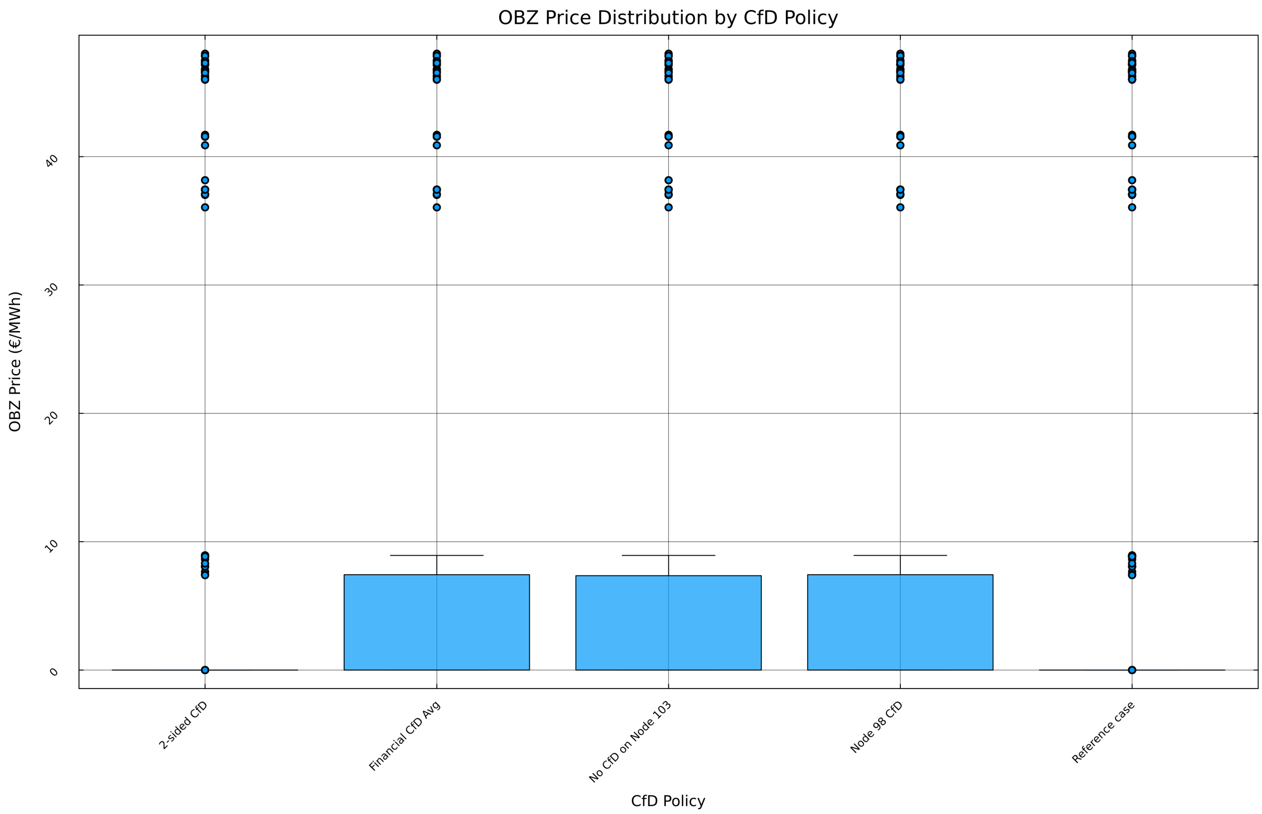


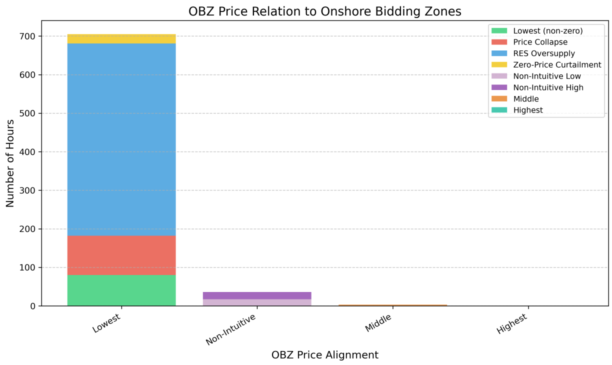
Figure 6.1: Distribution of Offshore Bidding Zone Prices Across CfD Policies

Figure 6.1 illustrates the distribution of OBZ prices under various CfD policy scenarios. The results highlight the significant influence of policy design on market-clearing prices and bidding behaviour in the OBZ.

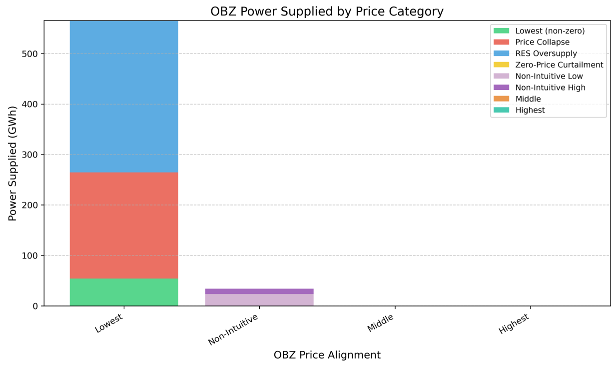
In both the reference case (no CfD) and the production-based, 2 sided CfD, OBZ prices consistently collapse to zero or near-zero values. The box plot shows that the average prices in the OBZ are near zero for more than 75% of the time, which underlines the risk for the investors in OBZs. Prices stay close to zero, with no meaningful spread. This is a result of OWFs bidding full capacity into a congested system, as there is no incentive to do otherwise.

In contrast, financial CfD designs introduce a change in the price profile in the OBZ. The prices are higher on average, but importantly, they spread out. The distribution widens, causing the median to shift upwards. This reflects a core behaviour of the OWFs. The CfD policy introduces dispatch variation by the OWF generators through bidding in response to the policy. There is partial or complete self-curtailment exercised by the OWFs, which leads to differences in bids altering the net position of the OBZ and its interaction with the surrounding zones. This indicates that CfD design can affect market-clearing prices not by influencing bid values directly, but by altering the volume of energy accepted and cleared at each node. The resulting price diversity is driven by bidding patterns engineered to maximise subsidy alignment. The observed price diversity under Financial CfDs stems from strategic bidding behaviour, where OWFs adjust their output to align with the reference generator's dispatch. Since clawback penalties are triggered by deviations from the reference, bidding in line with the reference becomes a rational strategy to protect subsidy income.

Figure 6.2 illustrates the frequency and magnitude of price-related risks in the offshore bidding zone under the Market-Only case (no CfD). Without any CfD in place, the OBZ operates under pure market conditions. Price collapse is frequent (102 hours), renewable oversupply dominates (499 hours), and OWFs flood the grid regardless of price signals. Curtailment (24 hours) is entirely a physical



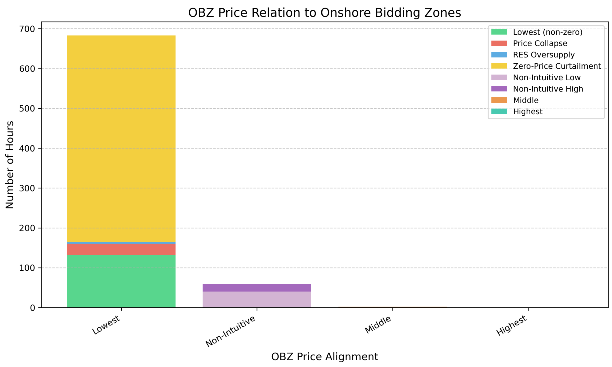
(a) Price risk frequency in the reference case



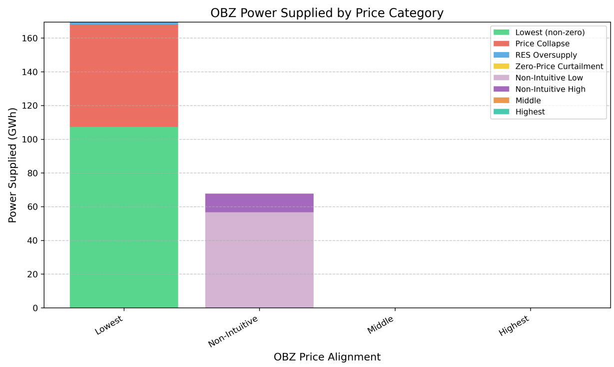
(b) Price risk magnitude in the reference case

Figure 6.2: Offshore bidding zone price behaviour under the reference case

consequence of grid constraints, not strategy.
Most of the energy is delivered during the unfavourable pricing conditions: zero-price hours, oversupply or under distorted price signals. This shows that price signals fail completely, and OWFs have no financial reason to adjust and offer up their entire potential on the market.



(a) Price risk frequency in the financial CfD with the reference generator as the average dispatch of the OBZ

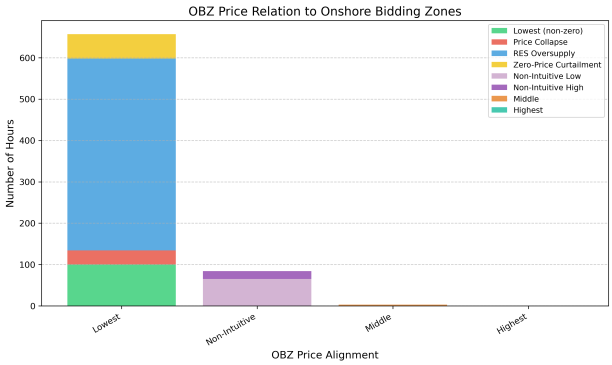


(b) Price risk magnitude in the financial CfD with the reference generator as the average dispatch of the OBZ

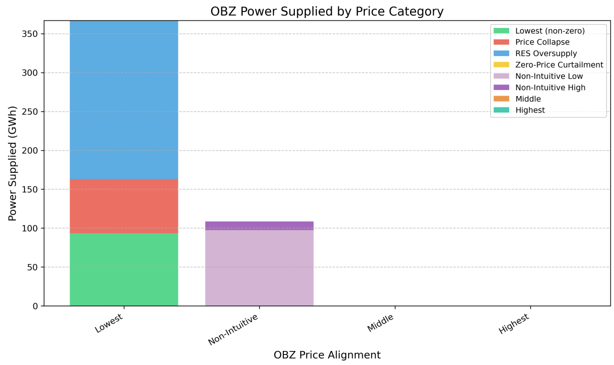
Figure 6.3: OBZ price behaviour under the financial CfD with reference generator as average dispatch of the OBZ

Figure 6.3 illustrates the price behaviour of the offshore bidding zone under the financial CfD scheme, with the reference generator defined as the average dispatch of the OBZ. Under this case, oversupply nearly disappears (5 hours), and price collapse drops to 28 hours. This seems like an improvement, but it is, however, superficial. It is caused by the 518 hours of total curtailment deliberately exercised by OWFs to align with the reference generator. Energy is withheld not because the system is full, but because the contract rewards it. Non-intuitive prices still occur in 59 instances, showing that manipulation of bids still introduces misaligned market outcomes. Only 2 hours fell into the middle price category, and no hours were recorded in the highest category.

Panel (b) shows that the majority of OBZ energy was supplied during hours categorised as lowest-price conditions, with significant contributions under price collapse hours. A smaller but notable portion of energy was dispatched during non-intuitive price conditions, while negligible generation occurred under middle or high alignment categories.



(a) Frequency of OBZ price categories under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.



(b) Magnitude of OBZ price deviations under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

Figure 6.4: OBZ price behaviour under asymmetric financial CfD allocation (nodes 119 and 120 contracted, node 124 uncontracted).

Figure 6.4 illustrates the price behaviour of the offshore bidding zone under an asymmetric financial CfD policy, in which nodes 119 and 120 are covered by CfD contracts, while node 124 remains exposed to market prices. This asymmetry creates a divergence in incentives, resulting in conflicting operational behaviours among the OWFs and introducing systemic inefficiencies into the bidding zone. Oversupply by wind comes down to 464 hours (62.36%), price collapse is recorded in 34 instances, and complete curtailment occurs 59 times. Most notably, non-intuitive price alignments reach 84 hours, which is the highest among all scenarios.

Energy delivery patterns are equally unbalanced. Panel (b) shows that most of the energy was supplied during hours when the OBZ had the lowest price, including significant contributions during price collapse and oversupply conditions. The market-exposed OWF injects power aggressively during low-price periods to chase revenues, while the contracted OWFs self-curtail to maximise CfD alignment. The behavioural divergence fractures the OBZ's internal consistency, making price formation erratic and unstable.

Renewable oversupply is highest in the Market-Only case (499 hours), nearly eliminated under the Uniform CfD (5 hours), and moderate in the Hybrid CfD (464 hours). The frequency of price collapse also drops with CfD adoption. However, the Hybrid CfD shows the highest number of non-intuitive low-price occurrences, indicating more complex price signals.

Localised price spread across nodes

While the previous results focused on the price levels and the frequency of risk events, Figure 6.5 shows a structural outcome of the CfD design. It illustrates the influence of the CfD policies on the prices across the OBZ. 30 hours with the highest observed price spread under different policy setups are seen in the figure.

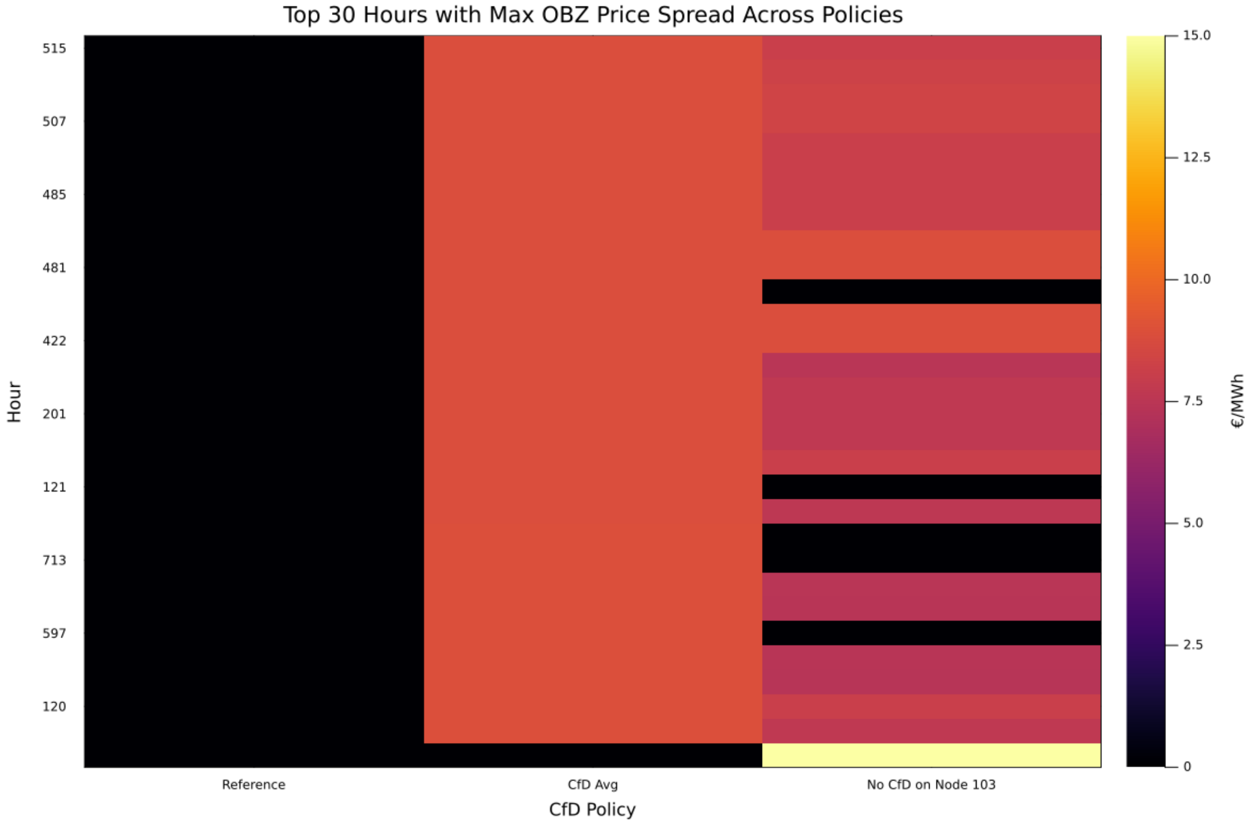


Figure 6.5: OBZ Price Variation Across CfD Designs for Top 30 Hours

The Reference case, shown entirely in black, confirms that the OBZ clearing price remained at 0 €/MWh during all selected hours, consistent with the assumption that OWFs bid without facing a volume constraint or policy-induced curtailment.
The 'Financial CfD Avg' column in the figure shows a uniform OBZ price across all 30 selected hours, indicated by the consistent red cells. The converged price for this CfD policy in instances where the bids cause a change is on average 8.22 € /MWh. This change is observed through a change in the bidding strategy brought about by the CfD policy applied. The policy structure pushes wind farms to develop a rational bidding strategy, where they dispatch equal amounts of energy. The output of the wind farms is for revenue maximisation, and market behaviour is contract-driven, causing dispatch distortions. OWFs optimise by offering volumes that match or slightly undercut the reference. This behaviour minimises payback obligations. Therefore, payback obligations become an important driver in the revenue maximisation of wind farms.

In contrast, the 'No CfD on Node 103' column exhibits considerable variation across the selected hours, with multiple instances of black (0 €/MWh), orange (approximately 10 €/MWh), and yellow (above 15 €/MWh) cells. In short, it produces the widest price spreads. The OWFs exposed to the market flood the grid when the prices are attractive, while the contracted OWFs withhold. This inconsistent bidding leads to non-production based CfD policies having a difference in prices compared to the reference case, driven by conflicting incentives within the same zone.

Uniform CfDs (financial CfD with the reference generator being the average dispatch in the OBZ) eliminate price spread through coordination, while Hybrid CfDs (financial CfD with one node exposed to the market) exacerbate price spread through contradiction. It can be seen that CfD design overrides market logic in some situations by suppressing or distorting price signals depending on how the contracts are applied. The prices in the OBZ are not only dependent on the grid constraints but also on how the wind farms are incentivised to bid.

Summary

In summary, financial CfDs address price risks effectively in aggregate terms, but also introduce distortions in bidding behaviour and nodal price formation. Their impact on price risk cannot be fully separated from the strategic responses they trigger.

Financial CfDs reduce price risks in aggregate: fewer zero-price hours, less volatility, and improved stability. However, these benefits are not costless. The price stabilisation observed under uniform CfDs is a result of strategic curtailment. OWFs limit output not due to technical constraints, but to avoid clawback penalties. This creates a form of rational underproduction that reduces dispatch by 362.51 GWh as compared to the reference case. This behaviour introduces dispatch patterns shaped by contractual structure, therefore designing a robust clawback mechanism is of utmost importance.

Asymmetric CfDs coverage introduces conflicting bidding behaviour that fractures the OBZ and leads to the most non-intuitive prices. While they allow some OWFs to respond to market conditions, the lack of incentive alignment undermines price coherence and introduces equity concerns.

6.1.2 Volume Metrics

The price outcomes analysed in the previous section are shaped by how OWFs bid into the market and how much of that energy is ultimately cleared. This section unpacks the mechanisms behind those outcomes by examining volume-related metrics. In particular, the analysis focuses on how different CfD designs change the relationship between offered volume, cleared power, and transmission constraints.

Overview of volume risks

Table 6.2: Volume risk metrics under Aligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Congested HVDC (h)	625	551	551	551	551	557
Capacity calculation (h)	394	0	0	0	0	21
Capacity allocation (h)	543	0	0	0	0	87

Table 6.2 presents key volume risk indicators across different CfD configurations. These include the number of hours with HVDC congestion, and occurrences of capacity calculation and capacity allocation risk, the two types of volume risk.
In the reference case and production-based CfD, volume risks are prominent. HVDC links are congested for 625 hours, with 394 hours of capacity calculation risk and 543 hours of capacity allocation risk, which relate to 52.95% and 72.98% of the total time, respectively. These outcomes reflect the inflexible bidding behaviour of OWFs that offer full capacity regardless of system constraints or market conditions. Without any revenue hedging, generators seek to maximise output, exposing the system to repeated oversupply.

Under financial CfDs, both capacity calculation and allocation risks are reduced to zero in most configurations, and HVDC congestion is reduced. However, these reductions result not from grid-side improvements, but from pre-emptive bid suppression. OWFs limit volume exposure to align with CfD references and avoid clawback penalties.

Interestingly, in the "No CfD on Node 103" case, where only one wind farm lacks CfD coverage, some residual volume risk re-emerges, with 21 hours of capacity calculation risk and 87 hours of allocation risk. This shows that even a single market-exposed OWF can introduce localised risk by bidding aggressively while the rest of the zone remains passive.

- Volume risks are highest under reference and production-based CfDs.
- Financial CfDs eliminate volume risk via strategic curtailment.
- Partial policy coverage (Node 124 uncontracted) reintroduces localised risks.

Bidding Behaviour and Strategic Curtailment

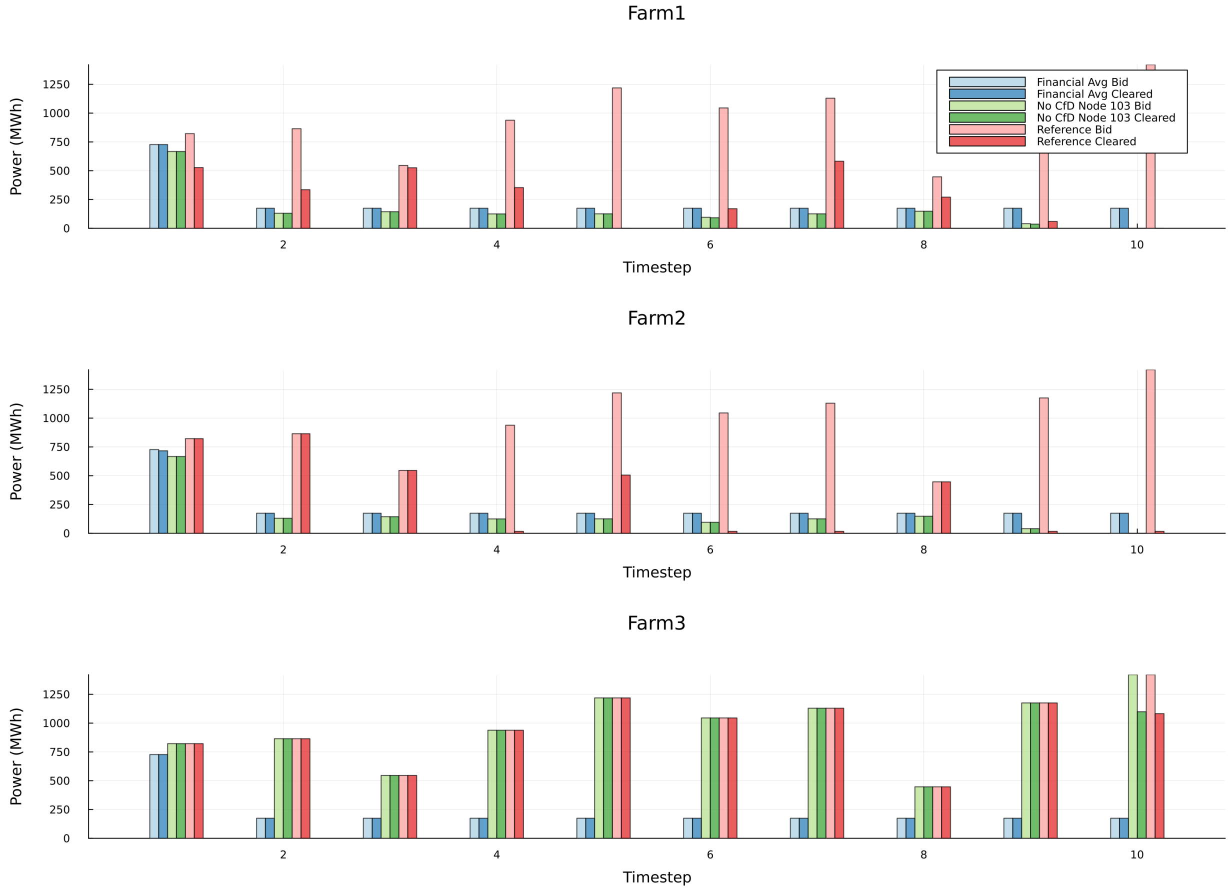


Figure 6.6: Bid and cleared volumes for three offshore wind farms across 10 high-impact time steps under different CfD policies

Figure 6.6 presents the offered (bid) and cleared power for the top 10 time steps with the greatest OBZ price divergence across three policy configurations: Reference (no CfD), Financial CfD Avg, and No CfD on Node 103. Each subplot corresponds to a specific wind farm (Farm 1, Farm 2, and Farm 3) in the OBZ. This figure allows direct observation of how policy and location influence bidding behaviour and market outcomes.

In the Reference case, all OWFs bid their full capacity, but Farm 3 consistently receives the highest cleared volume. This outcome is driven by the FBMC algorithm, which prioritises flows based on price signals and grid connectivity. OWF 3, located at Node 124, connects to Zone 2, a high-priced and relatively unconstrained demand area. This makes its energy socially more valuable to the system, despite its lower export line capacity.

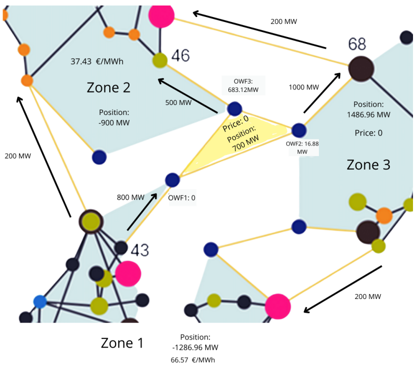
Under the financial CfD with an average-based reference, all OWFs reduce their offered volumes. The payment they receive depends on how their cleared output compares to the reference volume. If they generate more than the reference, they earn more; if less, they earn less. This creates an incentive to carefully match their dispatch to the reference. However, because the reference is influenced by all OWFs' performance and is not known in advance, bidding too high can introduce risk, especially for farms likely to clear more. To avoid ending up far above or below the reference, all OWFs suppress their bids. The result is that most of the offered volume is accepted, but total generation is well below what the system could handle.
This behaviour is most pronounced at Farm 3. Despite its locational advantage and higher likelihood of being cleared, it self-limits output to avoid deviating too far from the average reference. The grid itself does not enforce curtailment, yet effective curtailment emerges at the bidding stage, not from constraints, but from contractual optimisation.

In the asymmetric CfD coverage case, where only Farm 3 is market-exposed, it maintains high bids while the other two OWFs reduce theirs. This leads to an uneven dispatch profile: Farm 3 captures a disproportionately large share of cleared volume across several time steps, due to both its bidding strategy and locational advantage.

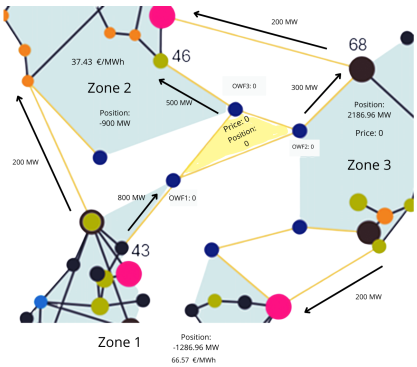
Overall, this figure highlights how CfD structures shape both bidding behaviour and dispatch outcomes. While financial CfDs reduce observed curtailment and volume risk, they introduce new inefficiencies, particularly strategic underutilisation of available capacity. These effects are examined more closely in the following time-step comparisons.

Operational Dispatch Patterns Under CfD Variants

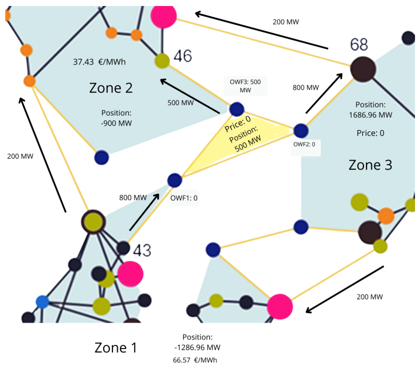
The strategic bidding tendencies discussed earlier translate into distinct dispatch patterns at the system level. This section explores these effects through selected time steps, highlighting how CfD design influences OWF curtailment, export volumes, and zonal interactions.



(a) Reference case (no CfD)



(b) Financial CfD – average reference



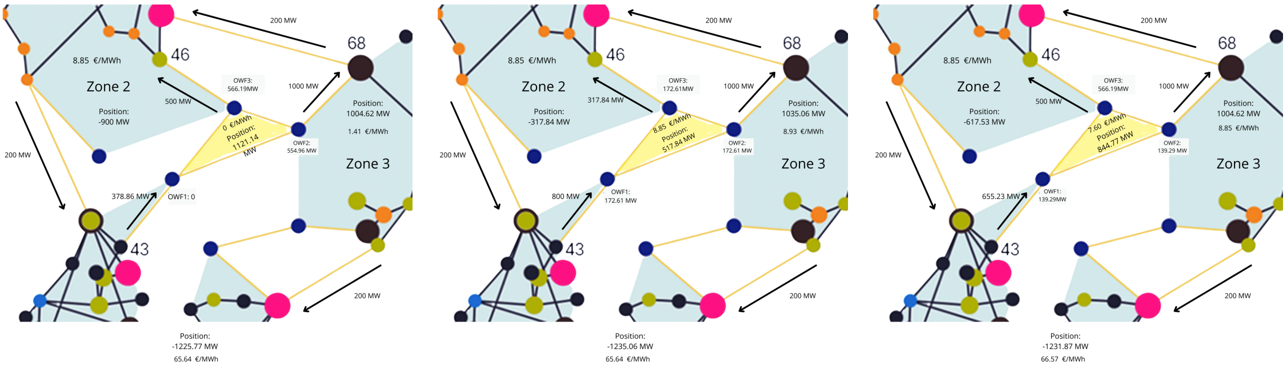
(c) Hybrid CfD – OWF3 market-exposed

Figure 6.7: Dispatch outcomes for timestep 90 under three policy scenarios: (a) reference case with no CfD; (b) financial CfD with average reference generator; (c) financial CfD applied to OWF1 and OWF2, with OWF3 exposed to market conditions.

Figure 6.7 illustrates how overproduction during a high-renewable period leads to price collapse in both Zone 3 and the OBZ. In the reference case, all OWFs bid at full capacity, but grid constraints result in complete curtailment of OWF1. OWF3, in contrast, dispatches 683.12 MWh, reflecting its locational advantage and priority in the flow-based clearing process.

Under the financial CfD, all three OWFs reduce their bids pre-emptively, resulting in the OBZ contributing zero net export to the grid during this timestep. In the hybrid CfD case, OWF1 and OWF2, both under CfD contracts, are fully curtailed. OWF3, being market-exposed, offers its full capacity and successfully dispatches 500 MWh after partial curtailment.
Additionally, the hydrogen electrolyser at node 68 operates at full capacity, benefiting from the surplus of low-cost renewable electricity in the system.

In this case, there are large-scale capacity allocation and capacity calculation risks leading to a lot of power offered by the OWFs being curtailed. Both of these risks are reduced to zero after introducing financial CfDs, however, the reason for this is that the wind farms curtail all of their wind. The OBZ, therefore, only acts as an interconnector without adding any power from the OWFs to the grid. OWFs bid zero during these timesteps not because the CfD disincentivises production in general, but because the marginal gain from dispatching more is negligible when prices approach zero. The dominant component of revenue becomes the fixed support payment, and OWFs rationally reduce bids to avoid exposure to uncertain dispatch patterns that provide no meaningful revenue upside.

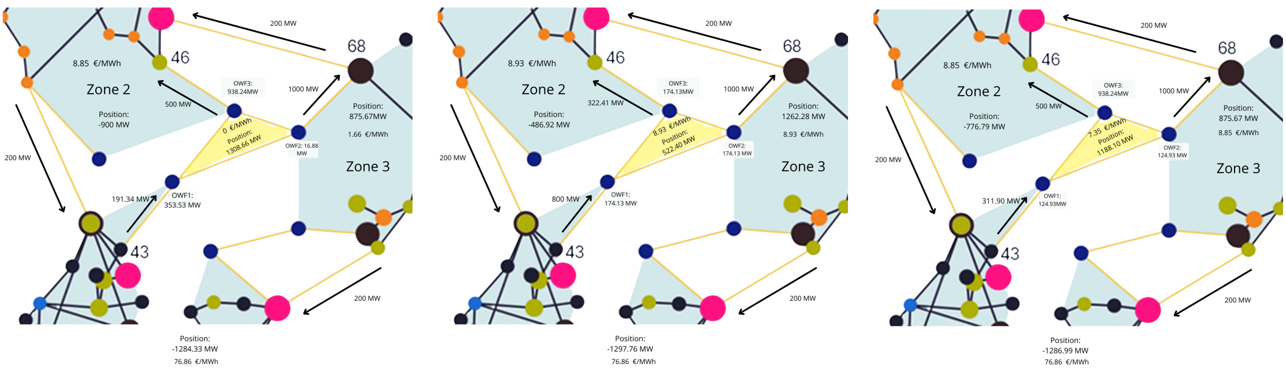


(a) Reference case (no CfD)

(b) Financial CfD – average reference

(c) Hybrid CfD – OWF3 market-exposed

Figure 6.8: Dispatch outcomes for timestep 111 under three policy scenarios: (a) reference case with no CfD; (b) financial CfD with average reference generator; (c) financial CfD applied to OWF1 and OWF2, with OWF3 exposed to market conditions.



(a) Reference case (no CfD)

(b) Financial CfD – average reference

(c) Hybrid CfD – OWF3 market-exposed

Figure 6.9: Dispatch outcomes for timestep 418 under three policy scenarios: (a) reference case with no CfD; (b) financial CfD with average reference generator; (c) financial CfD applied to OWF1 and OWF2, with OWF3 exposed to market conditions.

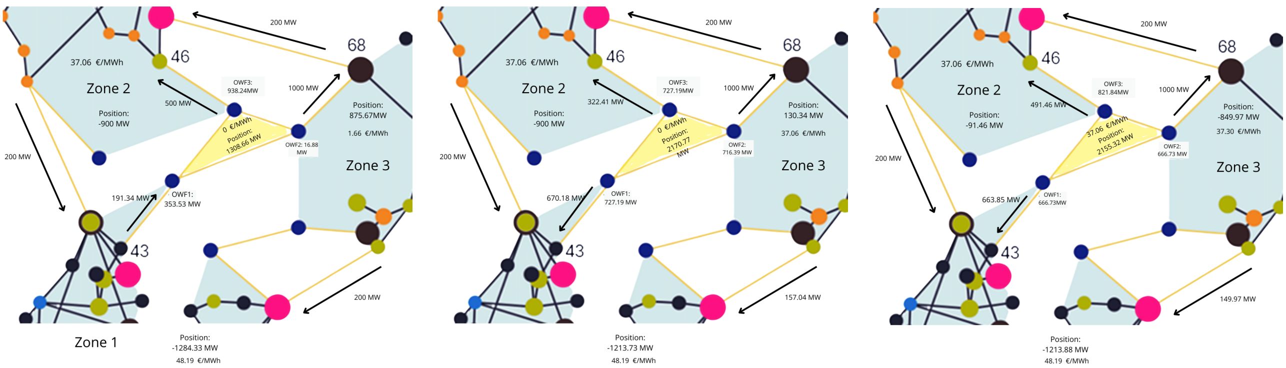
Figures 6.8 and 6.9 present dispatch outcomes for timesteps 111 and 418, respectively, under three policy scenarios. In both timesteps, OWF3 (node 124) consistently achieves the highest cleared volume. In the reference case (no CfD), OWF3 dispatches 566.19 MW in the first timestep and 938.24 MW in the second timestep, reflecting its favourable connection to Zone 2, which maintains a relatively high price of 8.85 €/MWh. Due to transmission constraints, OWF1 (node 119), connected to Zone 1 (65.64 €/MWh), is fully curtailed in both timesteps. OWF2 (node 120), connected to the lowest-priced Zone 3 (1.41 €/MWh in timestep 111 and 0 €/MWh in timestep 418), dispatches only 54.96 MW and 66.64 MW, respectively.

Under the financial CfD with an average-based reference volume, all OWFs self-curtail equally, dispatching 172.61 MWh in timestep111 and 174.33 MWh in timestep418. This uniform behaviour reflects strategic alignment with the expected reference to avoid revenue volatility. This results in OBZ net positions of 517.84 MWh and 522.40 MWh, respectively. In the hybrid CfD scenario, OWF1 and OWF2, being CfD-covered, curtail their entire output, while OWF3, being market-exposed, dispatches 566.19 MWh in timestep 111 and 938.24 MWh in timestep 418.

There is a capacity allocation risk where 577.42 MWh of energy is curtailed in the 111st timestep, while there is no capacity calculation risk. The capacity allocation risk arises due to the flow-based allocation procedure giving priority to cross-border flows. The OWFs under financial CfD tackle the capacity allocation risk by exercising self-curtailment so that each wind farm bids the same amount of power. All of the power generated by the wind farms is cleared in the market.
While in the 418th timestep, there is considerable capacity calculation and capacity allocation risk, with 637.90 and 868.16 MWh being curtailed, respectively. This is reduced to 0 under a financial CfD after partial self-curtailment, significantly reducing the position of the OBZ. Rather than bidding full capacity into a congested system, generators align with the expected reference dispatch to maintain stable payouts. This trade-off reveals a recurring pattern: OWFs restrict output not based on physical constraints or market prices, but to manage exposure under CfD contract logic.

Notably, this consistent advantage does not appear when OWF1 or OWF2 are exposed to the market under similar asymmetric configurations. Their bids, even at full volume, are less likely to clear due to higher congestion or weaker grid connectivity. This suggests that OWF3's dominance is not solely a result of being market-exposed, but of its favourable network position at Node 124.

These dispatch patterns underscore that the CfD contract structure increasingly drives OWF behaviour. Even generators with clear locational advantages reduce output to converge around the reference. While this eliminates curtailment from the system operator's view, it introduces hidden inefficiencies: grid capacity is available but not used, and locational diversity is underleveraged.



(a) Reference case (no CfD)
(b) Financial CfD – average reference
(c) Hybrid CfD – OWF3 market-exposed

Figure 6.10: Dispatch outcomes for timestep 522 under three policy scenarios: (a) reference case with no CfD; (b) financial CfD with average reference generator; (c) financial CfD applied to OWF1 and OWF2, with OWF3 exposed to market conditions.

Figure 6.10 presents dispatch outcomes for timestep 522 under three different policy scenarios. In the reference case (a), the OBZ price is 0 €/MWh. OWF1 (node 119) dispatches 355.53 MW. OWF3 (node 124) dispatches 938.24 MW while OWF2 (node 120) produces the least (16.88 MW). This shows a price collapse due to congestion, resulting in a lot of curtailment for OWF 1 and 2.
In the financial CfD case (b), the OBZ price remains 0 €/MWh. OWF1 dispatches 727.19 MW, OWF2 dispatches 716.39 MW, and OWF3 dispatches 727.19 MW, resulting in a total OBZ position of 2170.77 MW. Under a financial CfD, the OBZ exports all of its power, and the production in Zone 3 is greatly reduced. In the hybrid CfD case (c), the OBZ price is 37.06 €/MWh. OWF1 and OWF2 dispatch 666.73 MW each, while OWF3 dispatches 821.84 MW.

This case demonstrates that CfDs do not inherently cap OBZ exports, but they suppress bidding when volume risk is present. When network constraints are relaxed, OWFs will export, but still only up to the point that their contract logic allows.

Across all scenarios, CfD design reshapes not only OWF bidding behaviour but also the structural role of the OBZ. While financial CfDs reduce observable curtailment and mitigate volume risk, they do so by encouraging uniform bid suppression regardless of grid availability. This suppresses potential flexibility and reinforces nodal inequality: OWFs connected to better-positioned nodes (like Node 124) consistently secure higher cleared volumes, even when all farms are technically identical. The interplay between flow-based market logic and CfD incentives reveals a system where dispatch outcomes are shaped more by contract structure.
Bidding behaviour under policy scenarios influences the market-clearing solution and the price formation, not just in the OBZ but also in neighbouring bidding zones.

6.1.3 General Characteristics

This section examines how CfD configurations translate into revenue outcomes for OWFs and influence system-level dispatch efficiency. By assessing both distributional effects across OWFs and aggregate system impacts, it highlights the broader trade-offs embedded in different CfD mechanisms.

Table 6.3: General characteristics under Aligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Total wind generation (GWh)	599.70	237.19	237.19	237.19	237.19	475.35
Export at 0 price (GWh)	511.20	62.17	62.17	62.17	62.17	273.39
Revenue Farm 1 (€M)	0.50	2.50	1.43	5.42	1.28	2.42
Revenue Farm 2 (€M)	1.10	2.50	1.43	2.56	2.50	2.42
Revenue Farm 3 (€M)	3.20	2.50	1.43	2.56	2.50	1.70
Mean Rev Farm 1 (€/MWh)	673.79	3354.86	1920.00	3642.41	1722.41	3252.37
Mean Rev Farm 2 (€/MWh)	1473.18	3354.86	1920.00	1722.41	3354.86	3252.37
Mean Rev Farm 3 (€/MWh)	4301.37	3354.86	1920.00	1722.41	3354.86	2278.33

Table 6.3 summarises total wind generation, exports at zero price, and revenue outcomes for the three OWFs across all CfD configurations. While absolute revenue values cannot be directly compared due to different strike price assumptions and system states, the relative distribution of revenue within each scenario reveals how contract structure and grid position affect financial outcomes.

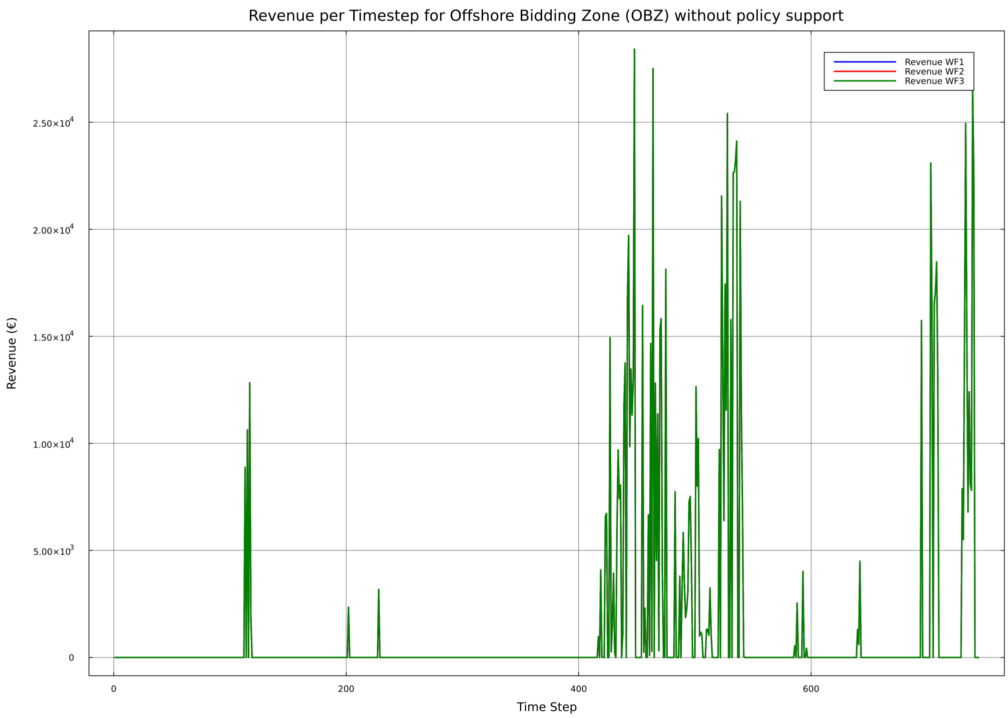


Figure 6.11: Revenue of the OWFs without policy support (reference case).

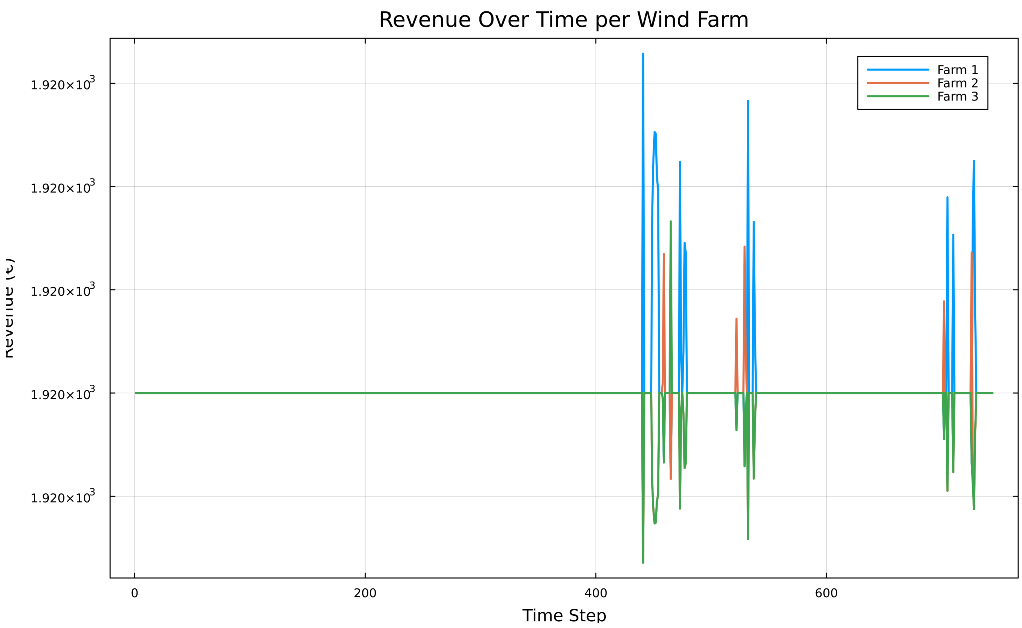


Figure 6.12: Revenue under a Financial CfD with average dispatched reference.

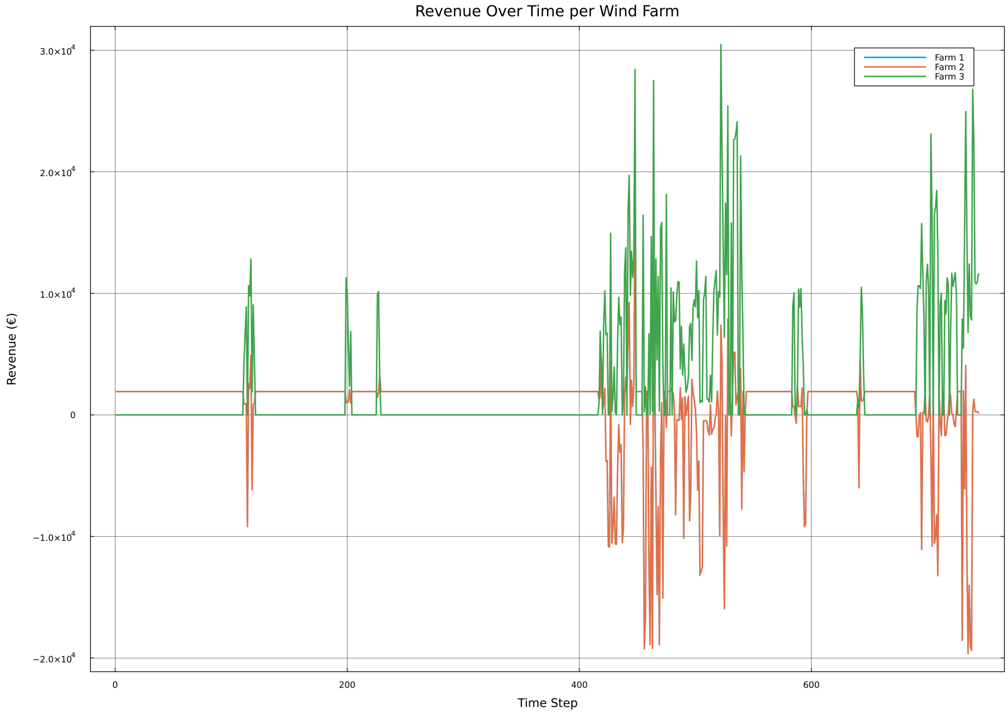


Figure 6.13: Revenue under a hybrid CfD policy excluding OWF 3 (Node 124).

The revenue over the timesteps shows that there is a lot of variation when there is no policy support. High revenues are seen during periods of high prices. However, for most of the time that the wind farm is operating, the revenue stays at zero. In Figure 6.20, the revenue becomes more stable. This is because a fixed payment is made for every timestep. Financial CfDs equalise revenues across OWFs and they flatten the time profile of revenue for each wind farm, derisking the predominant flat price risk in an OBZ. There is an incentive to beat the reference, which causes wind farms to bid in tandem with the other wind farms in the OBZ to collectively clear the maximum amount of energy.

One important observation from the figure is that the revenue profiles of all wind farms are the same. This happens because the wind profile and turbine technology are identical across the farms. The CfD design motivates the wind farms to bid equal amounts of energy. This way, each farm gets a fair share of the profits after the clawback is applied. The clawback is based on a reference generator, which is defined as the average dispatch of the wind farms in the zone. Since the clawback depends on how much each wind farm produces, the turbines coordinate and bid together. Deviating from the group average results in clawback penalties, encouraging aligned output. This bidding symmetry ensures equalised revenue, but it also constrains each OWF's ability to leverage individual locational advantages.

Figure 6.13 illustrates divergent behaviour under a hybrid CfD policy. The market-exposed OWF bids to maximise dispatch during high-price periods, while CfD-covered OWFs limit output to avoid clawbacks. As a result, the former accrues high spot-market revenue, while the latter face net deductions. This introduces asymmetric returns despite identical technical potential, raising concerns about fairness in shared infrastructure settings and potential barriers to coordinated development.

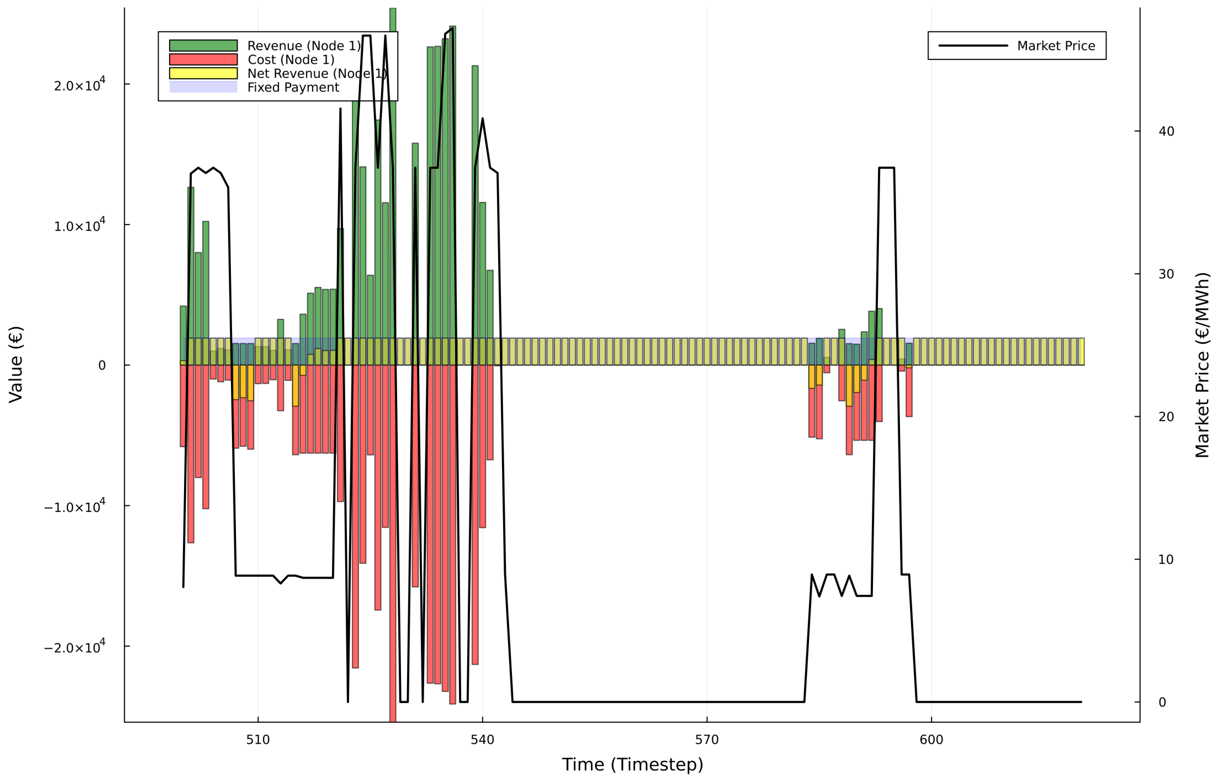


Figure 6.14: Financial CfD revenue dynamics

Figure 6.14 shows how revenue is generated over time for a short period between hours 500 and 620. In this figure, the yellow bars show the total revenue in each timestep. The green bars show the part of the revenue that comes from the market. The red bars show the clawback, which is the amount taken back from the wind farm in each timestep. There is also a fixed payment that was set during the auction. This payment stays constant and is shown as a straight line. From the figure, it is clear that the revenue of the wind turbine is uniform in each timestep. This is different from production-based CfDs, which usually lead to more variation in revenue depending on the amount of power generated.

The flatness of the yellow bar shows how financial CfDs effectively insulate generators from market volatility. The model has a high share of renewables in the system causing price volatility which mitigated effectively by this CfD design. However, the figure illustrates that the OWFs do not gain much from price spikes nor lose a lot during price dips. This stabilises income but reduces the system responsiveness.

Table 6.4: Revenue Comparison of Offshore Wind Farms under Different CfD Designs

Wind Farm	**2-Sided CfD (€M)**	**Ref = Node Avg (€M)**	**No CfD on Node 98 (€M)**	**Only Node 98 CfD (€M)**
Farm 1	0.50	2.50	1.28	5.42
Farm 2	1.10	2.50	2.50	2.56
Farm 3	3.20	2.50	2.50	2.56

This table shows the revenue earned by each wind farm under different CfD policies. The revenue values in this analysis are based on a simplified strike price, calculated using the average power dispatched and average market price within the offshore bidding zone. In practice, setting a proper strike price would require a more detailed study of the wind farm, accounting for long-term production forecasts, CAPEX and OPEX calculations. However, that is outside the scope of this thesis. In the reference case, Farm 3 earns disproportionately more due to favourable grid access to a high-priced zone. This locational advantage disappears under symmetric Financial CfDs, which flatten revenue profiles irrespective of physical position. While this promotes equity, it also removes incentives for siting generation in grid-efficient locations. While symmetric Financial CfDs promote revenue equity across OWFs, they also decouple revenues from physical grid position. In a government-allocated offshore setting, this ensures that location-based dispatch advantages do not translate into uneven financial outcomes but it may also reduce pressure on the planner to prioritise grid-efficient siting.

6.1.4 System Costs and Social Welfare

The comparison between Financial CfD configurations in this scenario highlights how the structure and coverage of the contract affect both dispatch behaviour and system costs. Under the Financial CfD with the OBZ average as the reference generator, all three offshore wind farms are covered by the contract and face identical incentives to align their output with the zonal average. This leads to coordinated curtailment: each OWF strategically reduces its output to avoid deviating from the reference and triggering clawback penalties. While this bidding behaviour stabilises revenue, it introduces a substantial generation cost penalty of approximately €580,000, reflecting dispatch inefficiencies as available renewable energy is withheld without technical or grid constraints.
By contrast, under the Financial CfD applied to two nodes while the third OWF remains exposed to the market, asymmetric incentives arise. The two CfD-covered OWFs continue to curtail their output to remain aligned with their reference, while the uncontracted OWF no longer subject to clawback risk, bids its full available volume into the market. This mix results in a lower additional generation cost of about €249,000, not because the contract structure itself is more efficient, but because the unconstrained OWF behaves according to market merit order while the others do not. However, this partial return to efficiency also comes with increased price distortion, with a slightly higher price effect cost (€9,400 vs. €8,300), as the uncontracted OWF disrupts the price convergence created by uniform curtailment.
These outcomes show that social welfare under Financial CfDs is heavily influenced by the simplified strike price selection, making absolute revenue or profit levels unreliable indicators of efficiency. Instead, the generation cost penalty and price effect cost provide a more robust basis for comparison. From this perspective, the Financial CfD with average-based reference introduces a higher system cost due to coordinated curtailment across all OWFs.

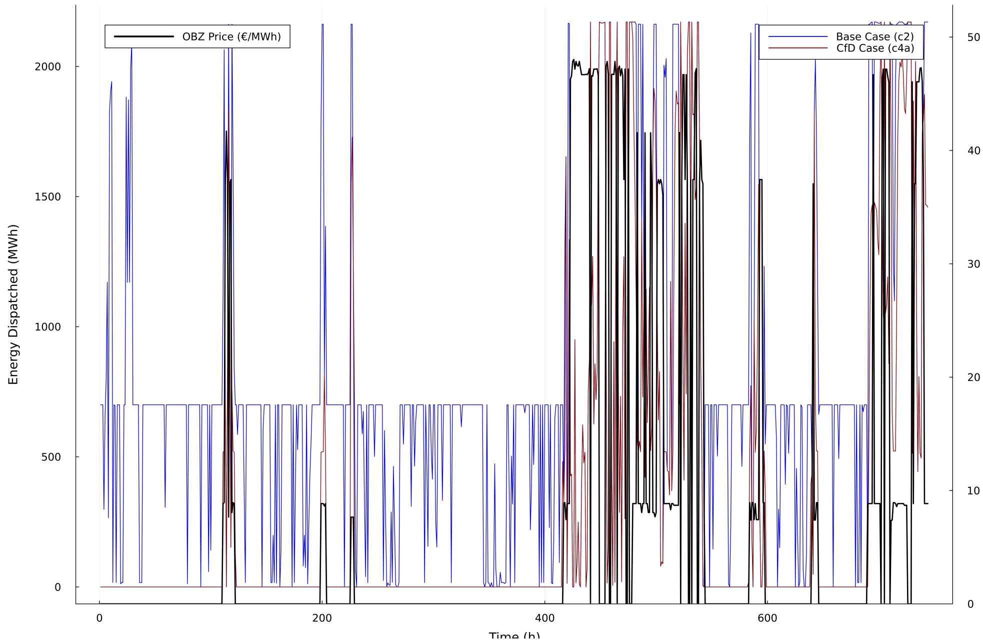


Figure 6.15: Comparison between power cleared in reference case and under Financial CfD

Figure **??** visually confirms the extent to which financial CfD structures suppress wind farm dispatch in Scenario 1. The plot compares the cleared output across time under the base case and under the financial CfD with average-based reference. It is evident that once the financial CfD is introduced, the cleared power in the OBZ drops dramatically and remains close to zero for a large portion of the year. This outcome is not a reflection of technical curtailment or grid congestion but is instead the result of strategic bidding behaviour incentivised by the clawback structure. Wind farms deliberately restrict output to align with the reference generator and avoid subsidy penalties. While this behaviour improves revenue stability, it also means that substantial volumes of renewable energy are never offered to the market, even when the grid has the capacity to absorb it.

The very mechanism that protects producers from market risk also induces them to curtail output voluntarily, undermining system-level efficiency. In this sense, the clawback-driven dispatch suppression represents a structural inefficiency embedded in the current design of financial CfDs.

6.2 Scenario 2: Misaligned Wind, Same Turbine Technology, No Offshore Electrolyser

This scenario has misaligned wind profiles and the same kind of turbine technology for all of the OWFs in the OBZ. The wind profiles are not temporally aligned to show the impact of having wind farms at considerable distances from each other in the same OBZ and exposed to the same policy schemes. There is no offshore hydrogen electrolyser in this case.

The objective is to assess how desynchronised wind output affects price formation, volume risk, dispatch behaviour, and revenue distribution in the OBZ under various CfD configurations. The results are compared against the base scenario with homogeneous wind conditions to highlight the effects of temporal wind misalignment. Only the outcomes that differ meaningfully from Scenario 1 are discussed, as the underlying model structure and CfD mechanisms remain unchanged.

6.2.1 Price Metrics

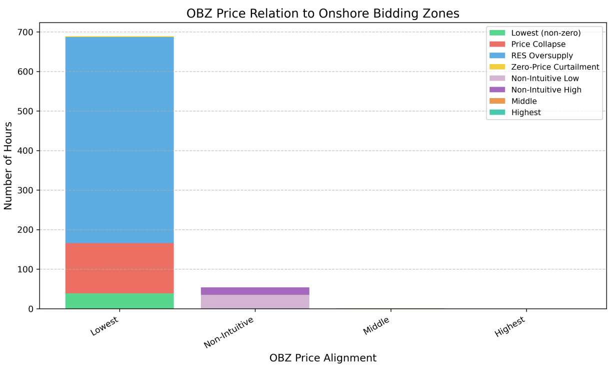
Table 6.5: Price risk metrics under Misaligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Mean price (€/MWh)	3.64	4.56	4.56	4.56	4.56	4.79
Std Dev	11.58	11.58	11.58	11.58	11.58	11.98
Variance	3.18	2.54	2.54	2.54	2.54	2.50
Low price hours (h)	562	584	584	584	584	589
– Zero price (h)	523	521	521	521	521	522
– Non-zero price (h)	39	63	63	63	63	67
Medium price hours (h)	1	0	0	0	0	1
High price hours (h)	0	0	0	0	0	0
Non-intuitive price (h)	181	160	160	160	160	154
– Zero price (h)	127	47	47	47	47	46
– Non-zero price (h)	54	113	113	113	113	108
Price delta (bids) (h)	56	188	91	91	91	82

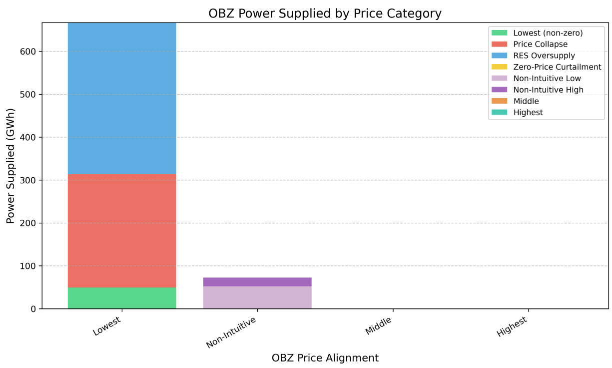
Table 6.5 presents the price risk metrics under misaligned wind conditions. In the production-based (2-sided) CfD case, the mean price is lowest at 3.64 €/MWh, reflecting a high number of hours with market saturation and zero-price outcomes. This configuration also sees the fewest medium-price hours (1) and the highest count of non-intuitive prices (219 hours), indicating that full-capacity bidding continues to trigger congestion and nodal distortion, similar to Scenario 1.

Financial CfDs raise and stabilise the mean price at 4.56 €/MWh across most cases, with marginally higher values in the 'No CfD on Node 103' case (4.79 €/MWh). This scenario also shows slightly increased price variability (standard deviation: 11.98), likely due to the aggressive, uncoordinated bidding of the market-exposed OWF. These changes reflect how partial market exposure disrupts CfD-induced price convergence.

Figures 6.16–6.18 show the distribution of price categories and dispatched volumes across key CfD configurations under misaligned wind. Compared to Scenario 1, the most notable shift is a sharp increase in non-intuitive low-price events, especially under Financial CfDs with an average reference (94 events vs. 36). This reflects how desynchronised generation complicates price formation and undermines collective bidding patterns.



(a) Price risk frequency in the reference case

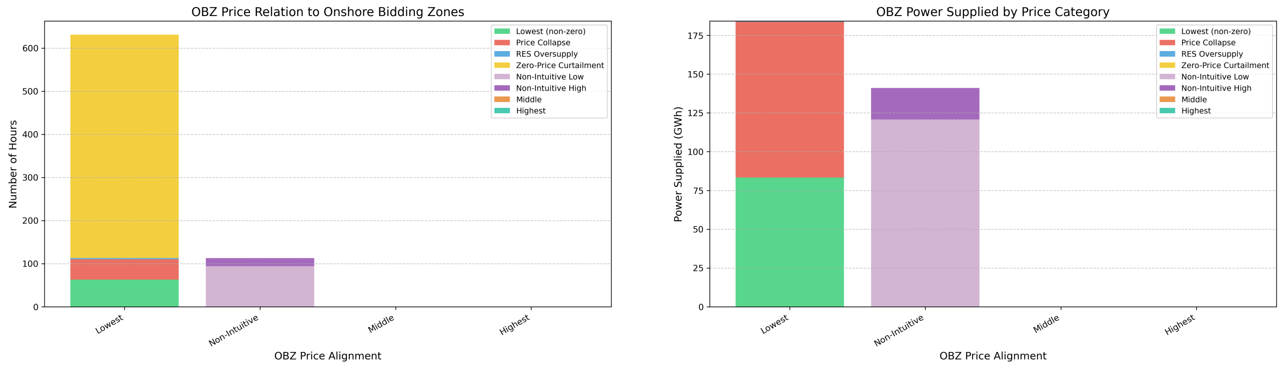


(b) Price risk magnitude in the reference case

Figure 6.16: Offshore bidding zone price behaviour under the reference case

In the 2-sided CfD reference case, curtailment remains concentrated in the lowest price category (39 events), with very few mid-price or zero-price instances. As in Scenario 1, full-capacity bidding under production-based CfDs leads to congestion-driven curtailment and price collapse. However, renewable energy oversupply is now more pronounced, resulting in 521 events indicating a rise from Scenario 1, indicating that misaligned wind can increase oversupply risk despite identical total capacity.

Only 2 curtailment events occur when the market price reaches zero and generation is fully curtailed. In terms of energy, 49.38 GWh is dispatched under the lowest price, 52.48 GWh under non-intuitive low, and 20.21 GWh under non-intuitive high. During the price collapse, 264.02 GWh is dispatched. Renewable energy oversupply results in 353.61 GWh of dispatched energy.



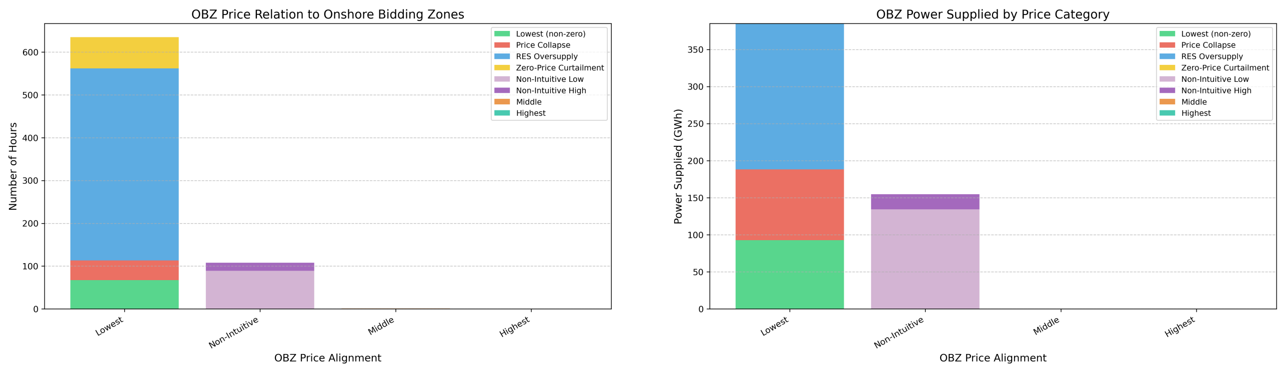
(a) Price risk frequency in the financial CfD with the reference generator as the average dispatch of the OBZ

(b) Price risk magnitude in the financial CfD with the reference generator as the average dispatch of the OBZ

Figure 6.17: OBZ price behaviour under the financial CfD with reference generator as average dispatch of the OBZ

Under full Financial CfD coverage (Figure 6.17), curtailment behaviour changes markedly. The number of zero-price, full-curtailment events jumps to 518, reflecting strategic non-bidding during saturated hours. This reduces observed oversupply events, but not because the system is less congested; rather, OWFs avoid participation when it offers no revenue benefit. Compared to Scenario 1, such strategic abstention is more frequent due to misaligned peaks, which prevent coordinated bidding.

Only 100.32 GWh is dispatched during price collapse, compared to 264.02 GWh in the reference case. Non-intuitive low-price dispatch rises to 120.83 GWh. These shifts confirm that financial CfDs reduce the occurrence of deep oversupply, but mainly by disincentivising bidding during problematic hours.



(a) Frequency of OBZ price categories under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

(b) Magnitude of OBZ price deviations under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

Figure 6.18: OBZ price behaviour under asymmetric financial CfD allocation (nodes 119 and 120 contracted, node 124 uncontracted).

In the Hybrid Case, two wind farms receive financial CfDs while the third does not. The hybrid

CfD case shows that wind misalignment allows the uncontracted OWF to inject large volumes during high-price hours, while the CfD-covered OWFs are forced to reduce their bids to avoid penalties. This results in a high number of non-intuitive events (108 events) and restores renewable energy oversupply (449 events) to near reference levels. Importantly, despite having fewer complete curtailment events at zero price than the uniform CfD case, the hybrid design still leads to a less coordinated system due to diverging incentives.
In energy terms, 92.80 GWh is dispatched under low-price events, and 134.42 GWh during non-intuitive low-price periods. RES oversupply contributes 196.73 GWh of output. These volumes show that although the system avoids extreme curtailment, it remains poorly coordinated under hybrid contracts.

In summary, misaligned wind output amplifies price risk by disrupting coordinated bidding. Financial CfDs still stabilise average prices and reduce price collapse frequency, but they are less effective at aligning dispatch when OWF output is asynchronous. As a result, medium-price hours rise, non-intuitive outcomes persist, and hybrid CfDs introduce price fragmentation. Under these conditions, price risk emerges not only from policy design but from generation timing a factor outside the operator's control.

6.2.2 Volume Metrics

Volume risks increase under misaligned wind conditions compared to Scenario 1. The loss of temporal synchronisation among OWFs causes more frequent instances of capacity-related curtailment, particularly due to inefficiencies in transmission allocation.

Table 6.6: Volume risk metrics under Misaligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Congested HVDC (h)	650	568	568	568	568	557
Capacity calculation (h)	427	0	0	0	0	84
Capacity allocation (h)	640	2	2	2	2	183

Table 6.7: Comparison of volume risk frequency (h) and severity (MWh) in Scenario 1 and 2

Volume Risk Type	Frequency (h)		Severity (MWh)	
	Scenario 1	Scenario 2	Scenario 1	Scenario 2
Capacity Calculation	394	427	507,246.61	301,257.60
Capacity Allocation	543	640	539,840.55	703,486.38

Table 6.7 compares the frequency and severity of volume risks across both scenarios. While the number of risk hours increases for both capacity calculation (from 394 to 427 hours) and allocation (from 543 to 640 hours), their energy impact diverges. Capacity allocation curtailment increases significantly from 539.8 GWh to 703.5 GWh (+30%). This indicates more frequent priority conflicts in the market-clearing process. In contrast, capacity calculation curtailment drops by 40%, from 507.2 GWh to 301.3 GWh.

This divergence reflects the distinct underlying mechanisms. Capacity calculation risk occurs when the total available wind generation exceeds the technical export capacity of the OWFs to the surrounding AC grid. In contrast, capacity allocation risk results from the market-clearing algorithm allocating transmission capacity to other zones with higher welfare gains, leaving the OBZ underprioritised even if it is locally feasible.

The reduction in capacity calculation curtailment suggests that wind misalignment spreads generation peaks across time, making it less likely for multiple OWFs to exceed local capacity limits simultaneously. However, this same temporal spread increases the number of hours where OWFs individually generate while cross-zonal competition is high, hence the increase in capacity allocation risk. This demonstrates that ultimately, curtailment increases in aggregate when the wind profiles are not aligned.

6.2.3 General Characteristics

Table 6.8: General characteristics under Misaligned Wind and Same Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Total wind generation (GWh)	740.07	325.21	325.21	325.21	325.21	540.05
Export at 0 price (GWh)	617.63	100.84	100.84	100.84	100.84	292.25
Revenue Farm 1 (€M)	1.14	1.29	1.43	2.41	1.27	1.14
Revenue Farm 2 (€M)	2.54	1.52	1.65	1.48	1.51	1.50
Revenue Farm 3 (€M)	2.24	1.41	1.55	1.38	1.41	1.83
Mean Rev Farm 1 (€/MWh)	2455.14	1736.20	1920.00	1653.02	1700.43	1527.92
Mean Rev Farm 2 (€/MWh)	4530.22	2029.53	2213.33	1993.77	2029.53	2020.73
Mean Rev Farm 3 (€/MWh)	4092.73	1892.94	2076.75	1857.18	1892.94	2459.25

The table 6.8 shows key characteristics under misaligned wind profiles across all CfD configurations. Compared to Scenario 1, the total wind generation in Scenario 2 is notably higher in the 2-sided CfD case (740.07 GWh vs. 599.70 GWh), due to the temporal spread of wind production. However, in all financial CfD configurations, total generation is significantly lower (325.21 GWh), nearly identical across cases. This reflects the impact of strategic self-curtailment under financial support schemes, which causes OWFs to align bids with expected reference output rather than maximise generation.

Export at zero price follows the same trend, with the highest in the 2-sided CfD (617.63 GWh), and much lower (around 100.84 GWh) in financial CfD cases. This shows that financial CfDs effectively reduce curtailment-induced zero-price dispatch, but at the cost of total energy injected into the system.

These results demonstrate that under misaligned wind profiles, temporal generation patterns become more influential than grid position in determining revenue under financial CfDs. Locational advantage alone does not guarantee higher revenue when CfD incentives drive coordinated curtailment. However, when an OWF is exempt from contract coverage (only in the case where node 124 is excluded from CfD coverage) grid access and exposure to market volatility enable it to outperform its CfD-covered peers.

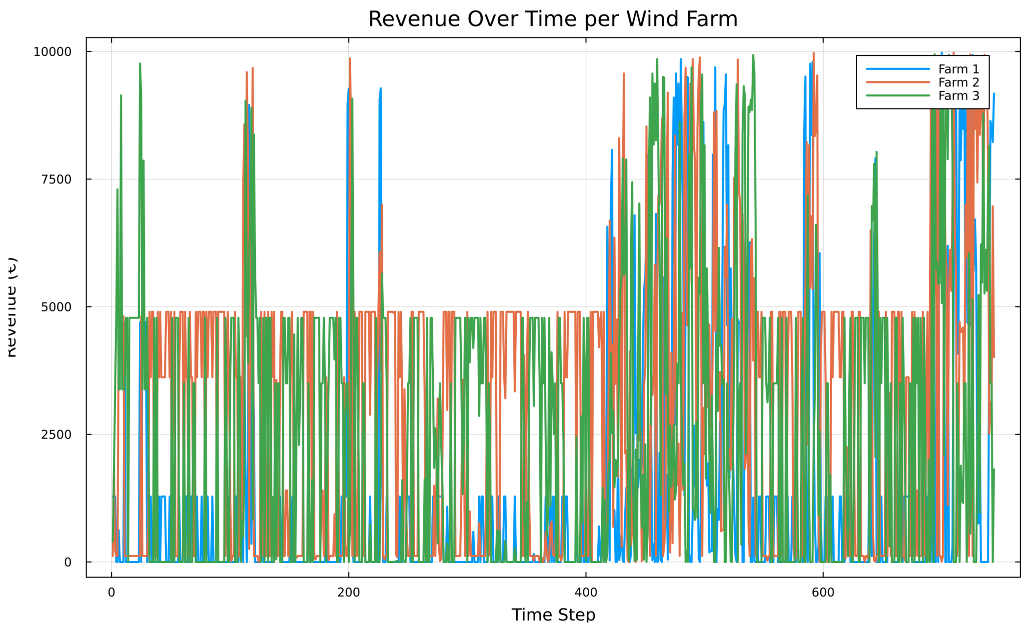


Figure 6.19: Revenue of the OWFs under a two-sided CfD

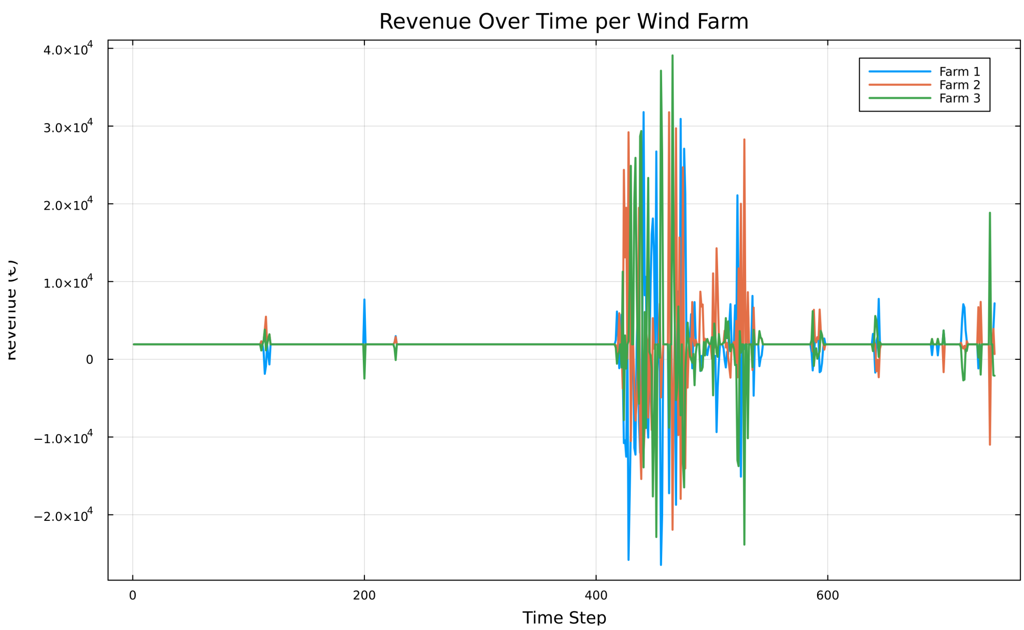


Figure 6.20: Revenue under a Financial CfD with average dispatched reference

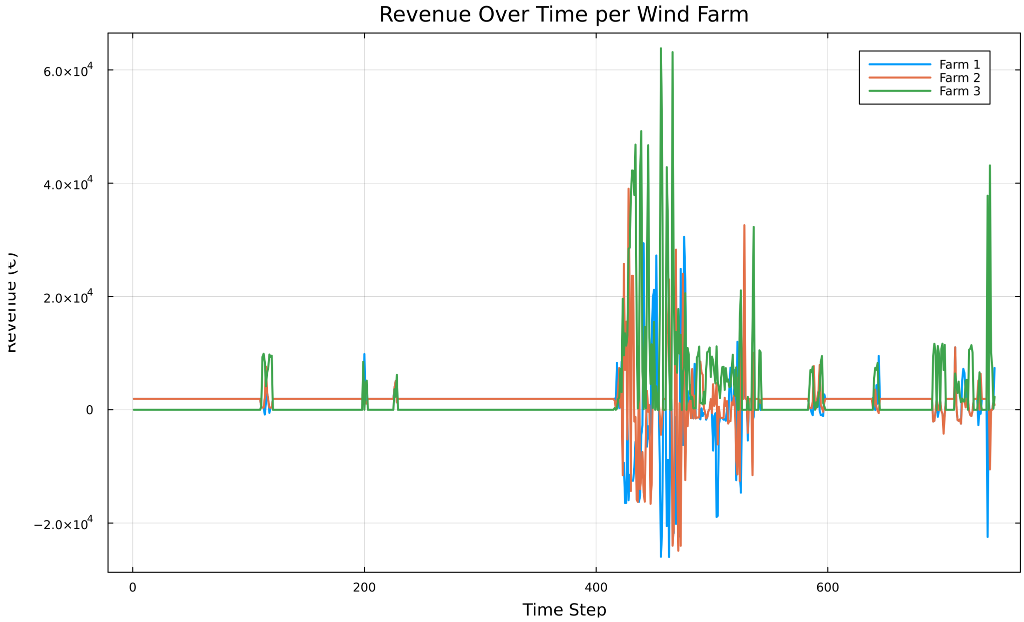
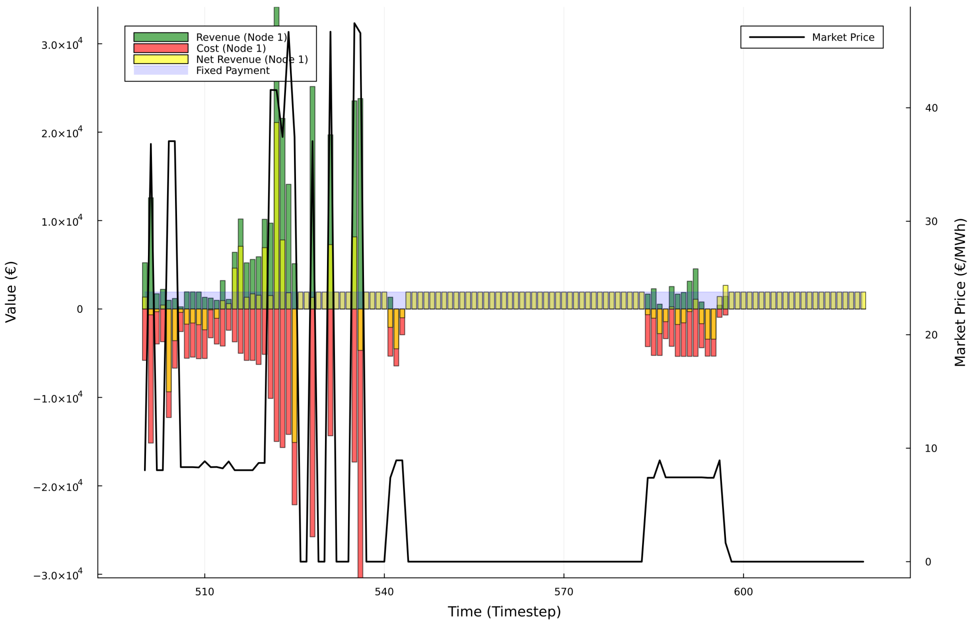


Figure 6.21: Revenue under a Financial CfD excluding OWF 3 (node 124)

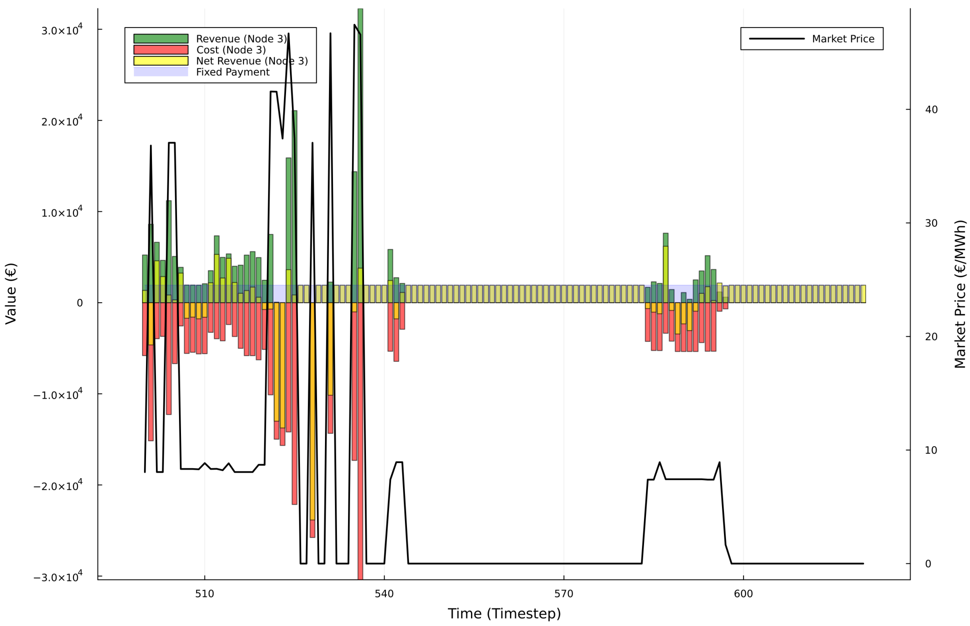
The revenue distribution across the time series shows that two-sided CfDs result in high revenues during periods when a large volume of power is dispatched. However, under a production-based CfD, the revenue is highly variable. There is a noticeable preference towards Wind Farm 3, which benefits from a more favourable grid connection, while Wind Farm 1 earns relatively lower revenues.

The third figure illustrates a scenario where two wind farms are under a financial CfD, and the third is exposed directly to the market. The wind farm without CfD support receives large revenues during periods of high prices. Since it is incentivised to bid at full capacity, the two wind farms under the CfD must adjust their bids strategically. Their goal is to ensure that, even with Wind Farm 3 bidding at full output, they can still secure the highest possible profits after clawback is applied. This coordinated bidding strategy is necessary to maximise revenue in this setting.

This dynamic does not apply in similar cases where wind farms apart from the one at node 124 are not under financial CfD support. In those cases, bidding large volumes does not guarantee high revenues. As the grid connection is less favourable, much of the power is not cleared due to limitations in capacity calculation and allocation. As a result, the volume of power that is cleared and earns revenue is largely influenced by the performance and positioning of the other wind farms.



(a) Revenue dynamics for Wind Farm 1 under a financial CfD



(b) Revenue dynamics for Wind Farm 3 under a financial CfD

Figure 6.22: Comparison of revenue dynamics for two wind farms under a financial CfD scheme over a selected time interval

There is a mismatch in the power produced in each timestep by the wind farms which leads to a misaligned wind profile. The OWFs bid strategically to beat the reference profile so that the maximum =revenue can be gained. This is demonstrated in the figure 6.22, wind farm 1 is able to produce more power when the price is high, therefore chooses to operate at maximum capacity, while wind farm 3 does not produce much during the same timestep leading to a disparity in the revenue. Like in the previous scenario, the wind farms chose to self curtail during large curtailment due to capacity calculation and capacity allocation effects. This can be seen in the revenue profile where the payment for a lot of timesteps is determined entirely by the strike price.

Under financial CfDs, revenue is determined not only by the total volume of energy produced but by the temporal alignment of generation with the reference output. Figure 6.22 demonstrates that Wind Farm 1 secures higher returns when its output coincides with high-price periods. Whereas Wind Farm 3, producing during lower-price intervals, receives only the fixed strike price or incurs deductions. This outcome highlights that even with identical turbine technology and capacity, wind farms experience unequal revenue outcomes purely due to differences in wind timing.
The clawback mechanism penalises OWFs for deviating from the reference volume, regardless of the market price. However, the financial impact of this deviation is amplified when it coincides with high-price hours, reducing gains when overproducing or worsening losses when underproducing. Thus, while the mechanism is volume-based, the cost of misalignment becomes more severe during periods of high price volatility. As shown by the red bars in Figure 6.22 between hours 510 - 540, Wind Farm 3 is disproportionately penalised due to its misalignment with the market-effective reference output. This mechanism can unintentionally widen revenue disparities under misaligned wind conditions, not because of operator behaviour, but due to unavoidable timing mismatches.

6.2.4 System Costs and Social Welfare

The social welfare effects of different CfD configurations in Scenario 2 capture the systemic trade-offs between revenue redistribution, dispatch efficiency, and market distortion under misaligned wind conditions.

In the full Financial CfD case (Ref = Node Avg), producer profits increase by €1.00 million compared to the production-based benchmark. However, this comes alongside an additional generation cost of €592,112 and a price effect cost of €23,003, resulting in a net welfare gain of €389,221. The welfare increase is primarily driven by the stabilisation of revenues, while the rise in generation cost reflects coordinated self-curtailment by OWFs to match the reference, even when technically unnecessary.

In contrast, the hybrid CfD configuration (No CfD on Node 103) sees a slightly higher gain in producer profits (€1.14 million) and a lower generation cost penalty of €436,727. The price effect cost also falls to €11,631, and the net social welfare gain reaches €691,090. These differences arise from the presence of one market-exposed OWF (Node 124), whose bidding behaviour is no longer influenced by the reference mechanism. As a result, some dispatch efficiency is restored, though this comes at the expense of alignment between OWFs and policy coordination.

The comparison underscores that welfare impacts are sensitive to how incentives are distributed across OWFs. Under misaligned wind profiles, full CfD coverage can trigger self-curtailment that is misaligned with system needs, whereas hybrid configurations introduce asymmetry in bidding behaviour that reduces total curtailment but can also disrupt collective outcomes. These effects should be interpreted within the context of system design, and not as absolute advantages of one configuration over another.

6.3 Scenario 3: Aligned Wind, Different Turbine Technology, No Offshore Electrolyser

This scenario examines the effect of heterogeneous turbine technology across wind farms in the OBZ, under aligned wind conditions and no offshore electrolyser. In Scenario 1 all OWFs operated with identical (least-performing) turbines. Scenario 3 assigns each wind farm a different performance level: Farm 1 uses the lowest efficiency turbine, Farm 2 uses the most efficient, and Farm 3 uses a medium-performing turbine. This setup allows for a direct evaluation of how turbine technology influences market outcomes such as price formation, curtailment exposure, and revenue generation, under similar conditions. The focus is on isolating the influence of turbine-driven output variation while holding CfD mechanisms and wind profiles constant.

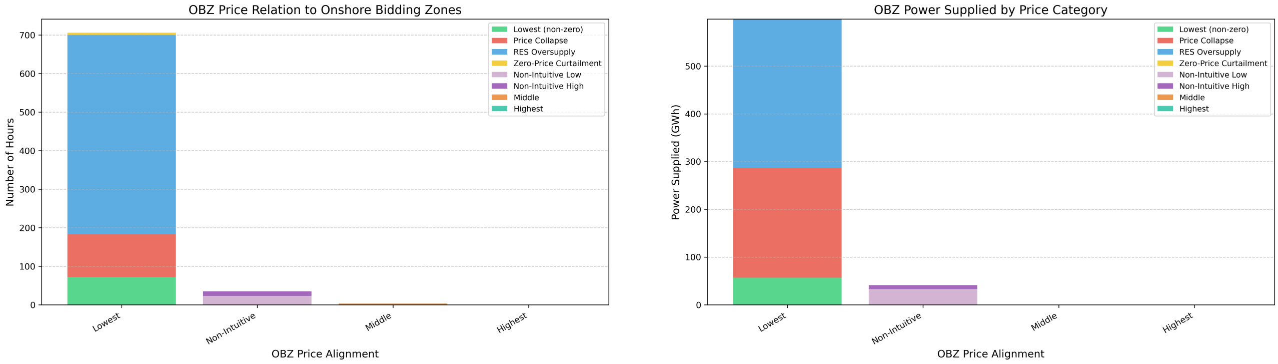
6.3.1 Price Metrics

Scenario 3 introduces heterogeneity in turbine technology while maintaining identical wind profiles across all OWFs. This allows a focused analysis of how turbine efficiency interacts with CfD configurations to influence price-related dynamics.

Table 6.9: Price risk metrics under Aligned Wind and Different Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Mean price (€/MWh)	4.56	5.91	4.79	5.91	5.91	6.05
Std Dev	11.58	13.42	11.98	13.45	13.45	13.45
Variance	2.54	2.72	2.50	2.28	2.28	2.28
Low price hours (h)	595	649	649	649	649	619
– Zero price (h)	523	523	523	523	523	523
– Non-zero price (h)	72	126	126	126	126	96
Medium price hours (h)	3	3	3	3	3	3
High price hours (h)	0	0	0	0	0	0
Non-intuitive price (h)	146	92	92	92	92	122
– Zero price (h)	111	33	33	33	33	36
– Non-zero price (h)	35	59	59	59	59	86
Price delta (bids) (h)	0	78	78	78	78	87

The average market price ranges from 4.56 €/MWh (2-sided CfD) to 6.05 €/MWh (No CfD on Node 103), reflecting slightly improved price formation due to differentiated bidding capacities. Similarly, price volatility increases. The standard deviation climbs from 11.58 in the 2-sided CfD to 13.45 under partial or asymmetric CfDs, suggesting more dynamic price responses when turbines are not equally efficient.
Non-intuitive price hours are lower in financial CfD configurations (92–153) compared to the 2-sided CfD (184), due to reduced OWF bidding volumes and increased self-curtailment. This limits the conditions under which distorted price signals typically arise. However, this does not necessarily imply more efficient dispatch. It rather reflects suppressed market participation, especially from less efficient turbines that are disadvantaged under reference-based CfDs. The price delta metric, which tracks hours with diverging bids among OWFs, is again zero under the 2-sided CfD and rises to as much as 145 hours under the average-reference financial CfD. This reflects strategic bid differentiation influenced by turbine performance.
The average price in Scenario 3 drops compared to Scenario 1, despite introducing higher-performing turbines. This counterintuitive result stems from reduced overbidding and more curtailment by less efficient OWFs. Better performing turbines produce more power during periods of low wind, gaining extra revenue by beating the reference.



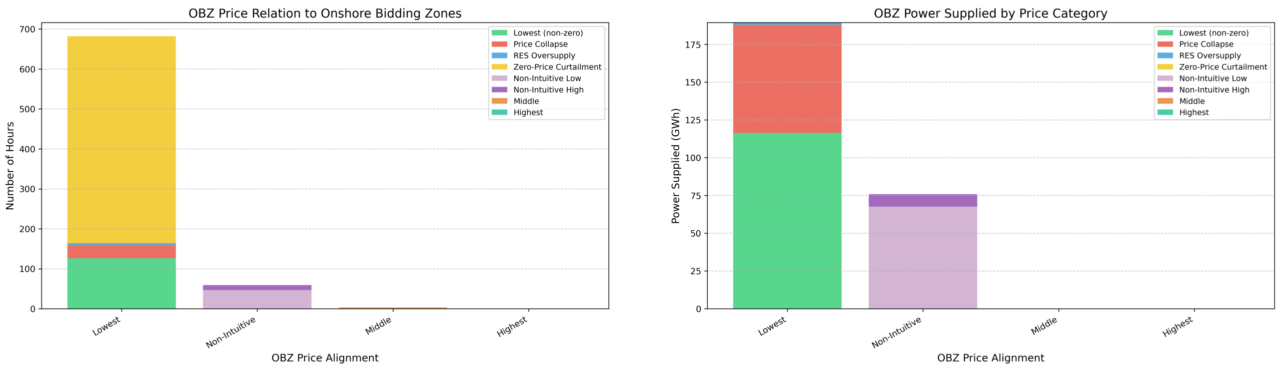
(a) Price risk frequency in the reference case

(b) Price risk magnitude in the reference case

Figure 6.23: Offshore bidding zone price behaviour under the reference case

In the reference case, which involves no policy support or a production-based Contract for Difference (such as a two-sided CfD), the number of timesteps with power dispatch under the lowest price category was 72. There were 3 timesteps in the middle price category and none in the highest. Power was also dispatched during 23 non-intuitive low-price hours and 12 non-intuitive high-price hours. Additionally, 111 timesteps were recorded with sharp price drops, and 517 timesteps with excess renewable generation relative to system demand. Complete curtailment occurred during 6 timesteps when the market price was zero. The corresponding power dispatched was 56.74 GWh under the lowest price category, 0.002 GWh under the middle price category, 33.08 GWh during non-intuitive low-price periods, and 8.22 GWh during non-intuitive high-price periods. During sharp price drops, 229.61 GWh was dispatched, and 312.05 GWh was dispatched when renewable generation exceeded demand. No power was dispatched during the zero-price curtailment events.

Compared to Scenario 1, where all turbines were identical and dispatch was more evenly distributed across farms. Scenario 3 shows that turbine heterogeneity amplifies disparities in both dispatch patterns and exposure to price-related events. While the total number of curtailment events is comparable, the underlying cause differs. In Scenario 3, high-performing turbines (e.g. OWF 2) dominate output, leading to frequent oversupply and sharper price drops, even as weaker turbines (e.g. OWF 1) remain underutilised. This creates a system where price and curtailment risks are tied to turbine-specific performance, making the CfD design's impact less predictable under technological asymmetry.



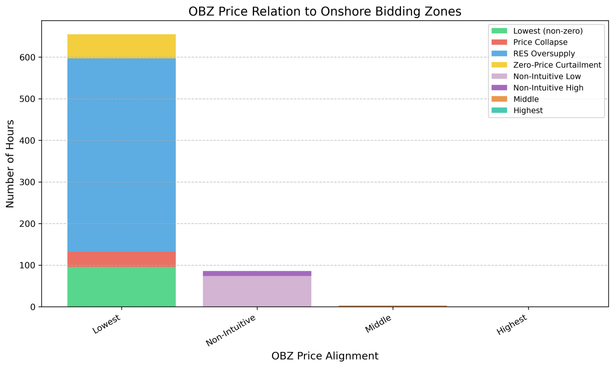
(a) Price risk frequency in the financial CfD with the reference generator as the average dispatch of the OBZ

(b) Price risk magnitude in the financial CfD with the reference generator as the average dispatch of the OBZ

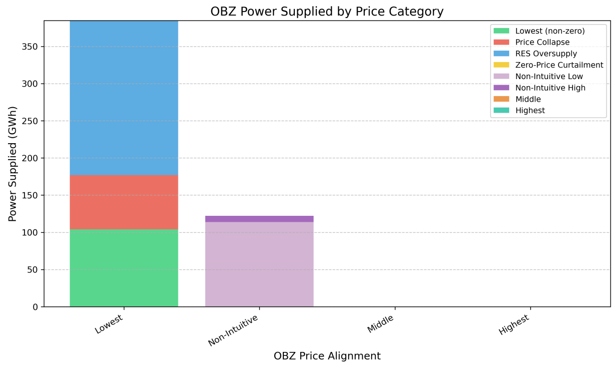
Figure 6.24: OBZ price behaviour under the financial CfD with reference generator as average dispatch of the OBZ

In the financial CfD case with the reference generator defined as the average dispatched power of all wind farms in the zone, there were 126 timesteps with power dispatch under the lowest price category and 3 under the middle category. No dispatch occurred under the highest price category. Power was dispatched during 47 non-intuitive low-price hours and 12 non-intuitive high-price hours. Additionally, there were 33 timesteps with sharp price drops and 5 timesteps with excess renewable supply. Complete curtailment occurred during 518 timesteps with zero market price. The dispatched power included 116.34 GWh under the lowest price category, 0.002 GWh under the middle category, 67.55 GWh under non-intuitive low conditions, and 8.22 GWh under non-intuitive high conditions. During hours with low market prices, 71.62 GWh was dispatched, and 1.40 GWh was dispatched during periods of excess renewable generation. No power was dispatched during the zero-price curtailment timesteps.

Under financial CfDs, the dispatch behaviour in Scenario 3 differs notably from Scenario 1 due to the performance variability of different turbines operating under the same wind profile. While the number of curtailment events increases by 518 timesteps with complete curtailment. Although financial CfDs reduce price volatility and stabilise revenues at the system level, they also cause OWFs with more efficient turbines to dominate the reference and force others to either accept lower margins or curtail entirely. This highlights a key limitation of financial CfDs under heterogeneous turbine conditions. In financial CfDs with an average-based reference, higher-performing turbines contribute disproportionately during high-price periods, effectively pulling the reference level upward.



(a) Frequency of OBZ price categories under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.



(b) Magnitude of OBZ price deviations under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

Figure 6.25: OBZ price behaviour under asymmetric financial CfD allocation (nodes 119 and 120 contracted, node 124 uncontracted).

In the hybrid CfD configuration, where two OWFs are covered and one remains market exposed, the system shows a mixed set of dispatch behaviours. There were 96 dispatch hours under the lowest price category, slightly fewer than Scenario 1's 102. However, non-intuitive low-price hours rise to 74 (36 in Scenario 1), and the associated dispatched energy nearly doubles to 114 GWh. Curtailment at zero price occurs in 58 timesteps, significantly more than the 24 events in Scenario 1. This reflects that even the covered turbines are pushed into curtailment due to congestion triggered by unregulated bidding. Meanwhile, excess renewable generation events are slightly fewer (465 vs. 499), but still substantial, with 208 GWh dispatched. The high-performance turbines quickly saturate system capacity. Overall, the market-exposed OWF introduces volatility into an otherwise contract-stabilised system, forcing CfD-covered farms to reduce output to avoid clawbacks or curtailment.

This section illustrates that turbine heterogeneity introduces additional distortions under financial CfDs. While these policies stabilise OBZ prices, they do not account for differences in turbine performance. As a result, higher-output OWFs disproportionately influence the reference signal, leading to misaligned bidding and dispatch imbalances. In hybrid configurations, this effect is amplified, not by design, but as an unintended consequence of exposing only certain OWFs to market incentives while others remain contracted.

6.3.2 Volume Metrics

Table 6.10: Comparison of volume risk frequency (h) and severity (MWh) in Scenario 1 and Scenario 3

Volume Risk Type	**Frequency (h)**		**Severity (MWh)**	
	Scenario 1	**Scenario 3**	**Scenario 1**	**Scenario 3**
Capacity Calculation	394	435	507,246.61	571,363.74
Capacity Allocation	543	559	539,840.55	580,407.69

In Scenario 3, both capacity calculation and capacity allocation curtailment volumes increase compared to Scenario 1, rising from 507 GWh to 571 GWh and 540 GWh to 580 GWh, respectively. This increase is particularly notable given that the wind profiles are identical in both scenarios. The difference, therefore, arises entirely from the variation in turbine efficiency.

The higher-performing turbines in Scenario 3 (particularly at Farm 2) generate significantly more power under the same wind conditions, leading to a greater concentration of output at individual nodes. This uneven power injection causes the system to hit local export capacity limits more frequently, resulting in increased capacity calculation curtailment. Meanwhile, the imbalance in output also means that some OWFs consistently dominate the market, which crowds out lower-producing farms.

Unlike Scenario 2, where the temporal misalignment of wind caused fluctuating system-wide constraints. The grid, in this scenario, experiences congestion because some turbines inject more power than others under the same conditions. This shifts curtailment pressure disproportionately onto the lower-performing turbines, which are less likely to secure cleared volume in congested intervals. As a result, technological asymmetry alone is enough to cause more frequent curtailment.

6.3.3 General Characteristics

Table 6.11: General characteristics under Aligned Wind and Different Turbine Technology, No Offshore Electrolyser

Metric	**Production-Based CfD**	**Financial CfD**				
	2-Sided CfD	**Ref = Node Avg**	**Ref = Node 98**	**Only Node 98 CfD**	**No CfD on Node 98**	**No CfD on Node 103**
Total wind generation (GWh)	639.70	265.14	265.14	265.14	265.14	506.87
Export at 0 price (GWh)	100.84	73.02	73.02	73.02	73.02	280.62
Revenue Farm 1 (€M)	0.43	0.95	1.43	1.54	1.07	0.86
Revenue Farm 2 (€M)	2.22	1.61	2.09	1.73	1.61	1.53
Revenue Farm 3 (€M)	2.47	1.17	1.65	1.29	1.17	1.85
Mean Rev Farm 1 (€/MWh)	577.92	1277.95	1920.00	2074.43	1435.35	1162.69
Mean Rev Farm 2 (€/MWh)	2985.43	2170.76	2810.81	2328.16	2170.76	2060.32
Mean Rev Farm 3 (€/MWh)	3315.12	1572.87	2214.92	1730.27	1572.87	2481.52

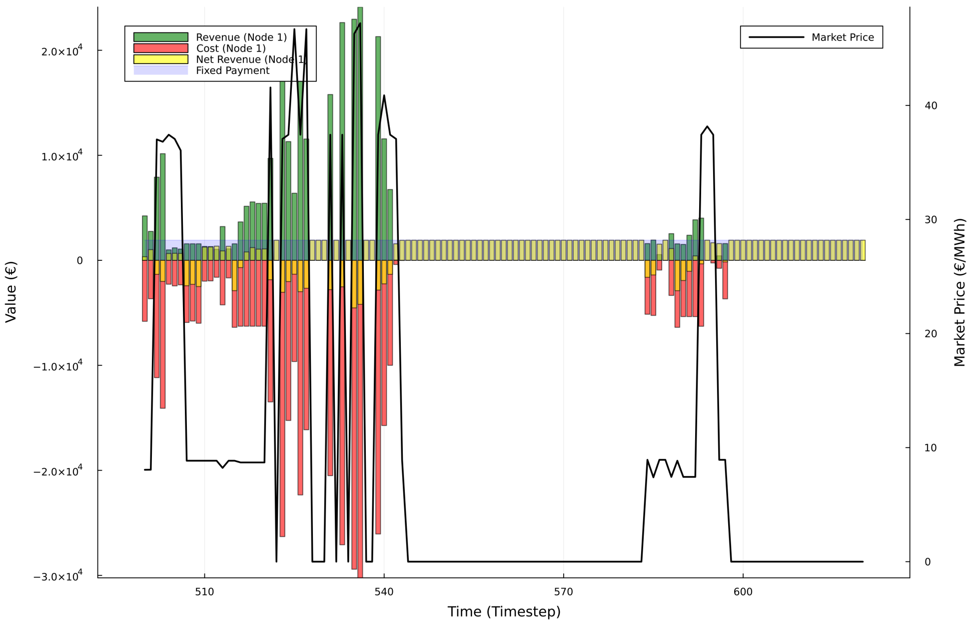


Figure 6.26: Financial CfD revenue dynamics at node 119

	Production- based CfD		Financial CfD					
Revenue (M €)	2-sided CfD		Ref = avg		Ref = node 98		No CfD = node 103	
Wind Farm 1	0.50	0.43	2.50	0.95	1.43	1.43	2.42	0.86
Wind Farm 2	1.10	2.22	2.50	1.61	1.43	2.09	2.42	1.53
Wind Farm 3	3.20	2.47	2.50	1.17	1.43	1.65	1.70	1.85

Table 6.12: Comparison of revenues between Scenario 1 and 3

The two columns within each CfD model in table 6.12 shows the difference in revenues between Scenarios 1 and 3. In Scenario 1, identical turbines lead to equal bidding and symmetric revenues. In Scenario 3, turbines with a lower output face lower clawback penalties when used as the reference generator. Wind Farm 1 (the least efficient turbine) suffers in all cases except when chosen as the reference, while Wind Farm 2 (the most efficient turbine) consistently earns more. This confirms that both grid location and turbine performance influence revenue, especially under financial CfDs.

Figures 6.26 and 6.27 illustrate the revenue dynamics for Wind Farms 1 and 2 under a financial CfD scheme with an average reference generator. The plots break down total revenue into fixed payments (yellow bars), market revenue (green bars), and clawback (red bars).
Wind Farm 2, equipped with the most efficient turbine, earns the highest share of market revenue during high-price hours. In contrast, Wind Farm 1, being the least efficient, frequently incurs net payments. Particularly during the same high-price hours. This is because the better-performing Wind Farm 2 elevates the reference output used in the clawback calculation. As a result, Wind Farm 1 is penalised for falling short of this reference when prices are high.

This dynamic introduces a systemic bias. When similarly contracted OWFs face the same strike price and are benchmarked against an average reference, the revenue distribution favours the farms with high-volume, high-output turbines. Consequently, there is a strong incentive for project developers to deploy higher-capacity or higher-efficiency turbines when participating in financial CfD schemes, espe-

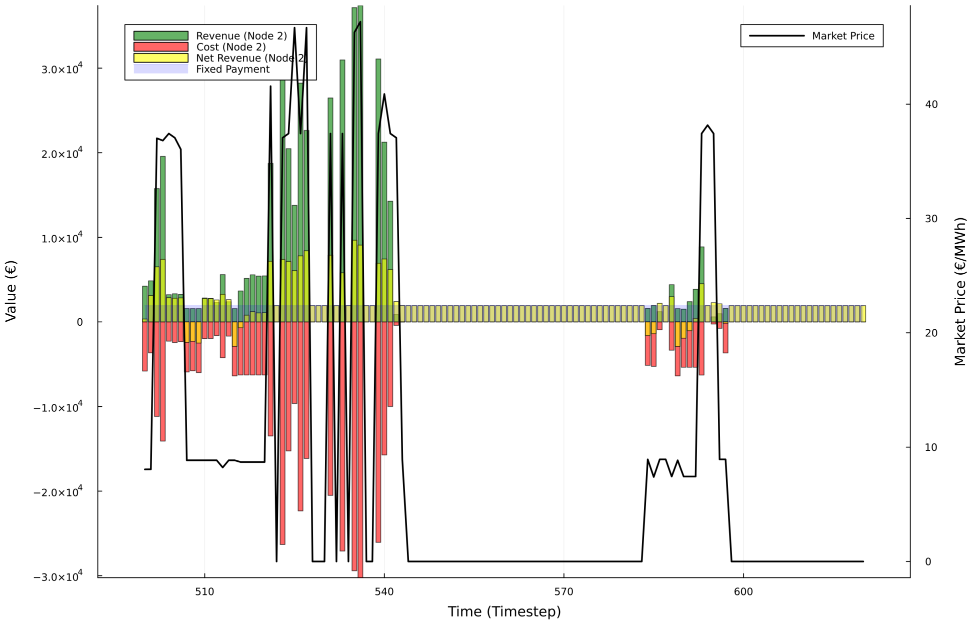


Figure 6.27: Financial CfD revenue dynamics at node 120

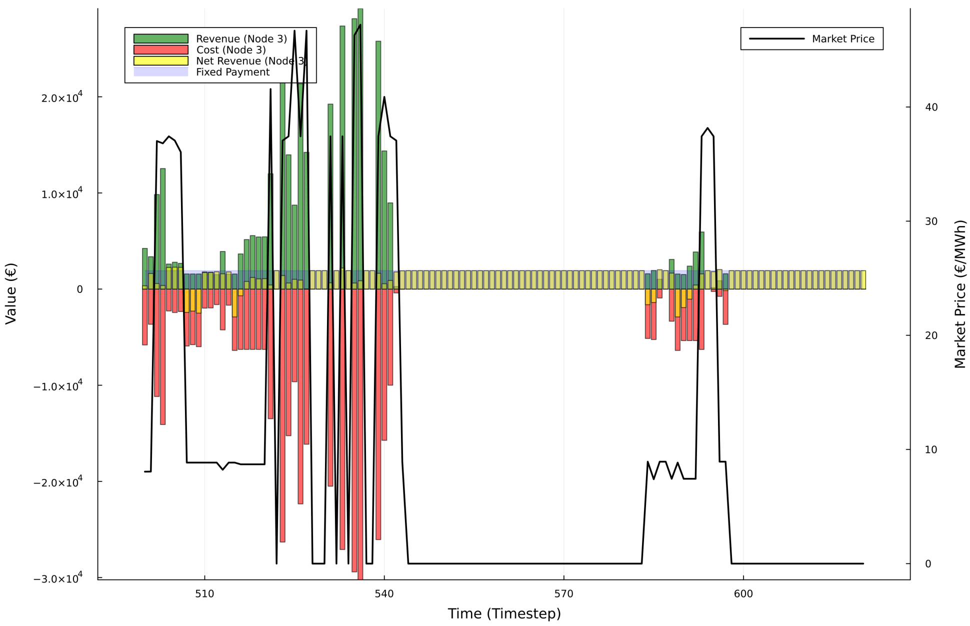


Figure 6.28: Financial CfD revenue dynamics at node 124

cially in configurations where average references are used. This drives the lower-performing, cheaper turbines to curtail output to avoid excessive clawbacks. The inefficient dispatch causes cost-effective generation to be withheld despite available capacity.

6.3.4 System Costs and Social Welfare

In the Financial CfD with an average reference, producer profits rise by €1.13 million relative to the production-based benchmark. This gain is accompanied by an increase in generation costs of €588,924 and a modest price effect cost of €8,303, resulting in a net welfare improvement of €530,778. The increase in welfare reflects smoother revenue profiles and reduced exposure to price volatility. However, some efficiency losses arise from constrained bidding, as farms with lower output adjust behaviour to avoid unfavourable outcomes relative to the average.

In the hybrid configuration (No CfD on Node 103), welfare improves further. Producer profits reach €1.26 million, while generation costs fall to €284,793, and the price effect cost remains low (€2,206). The resulting social welfare gain of €968,868 suggests that allowing partial market exposure introduces more flexible dispatch decisions. Here, the uncontracted OWF bids competitively during high-value periods, while the contracted OWFs moderate their output based on shared contractual incentives.

6.4 Scenario 4: Misaligned Wind, Different Turbine Technology, No Offshore Electrolyser

Scenario 4 examines the combined impact of wind profile misalignment and turbine heterogeneity on market outcomes within the Offshore Bidding Zone (OBZ), excluding any offshore electrolyser deployment. Unlike Scenario 1, where all OWFs used identical turbines, and Scenario 3, which assumed aligned wind profiles, this scenario introduces both turbine and wind variability. Each wind farm now operates with a different turbine and a unique wind profile, creating more realistic system complexity.

This setup reflects a likely future where offshore wind farms are geographically spread and tailored to local wind conditions. The aim is to understand how this heterogeneity impacts price formation, volume risk, curtailment, and revenue outcomes under different CfD schemes.
By comparing results to earlier scenarios, this section shows how mismatched wind output and unequal turbine performance interact with policy design. These factors can reduce congestion but may also increase disparities in revenue and bidding strategies across wind farms.

6.4.1 Price Metrics

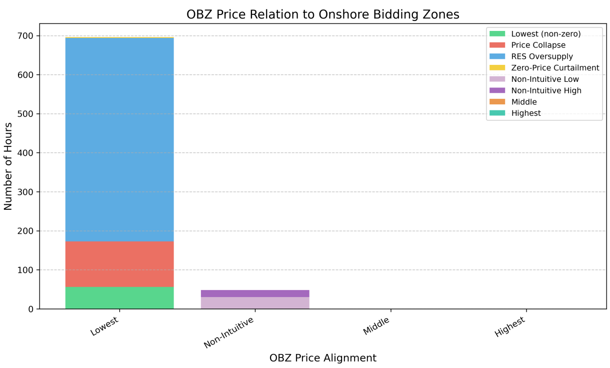
Table 6.13: Price risk metrics under Misaligned Wind and Heterogeneous Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Mean price (€/MWh)	5.76	5.10	5.10	5.10	5.10	5.15
Std Dev	14.51	12.36	12.36	12.36	12.36	12.53
Variance	2.52	2.42	2.42	2.42	2.42	2.43
Low price hours (h)	546	606	606	606	606	603
– Zero price (h)	521	521	521	521	521	522
– Non-zero price (h)	25	85	73	73	73	81
Medium price hours (h)	0	0	11	11	11	0
High price hours (h)	0	0	0	0	0	0
Non-intuitive price (h)	198	138	139	139	139	141
– Zero price (h)	127	40	47	47	47	44
– Non-zero price (h)	71	98	92	92	92	97
Price delta (bids) (h)	61	198	198	198	198	150

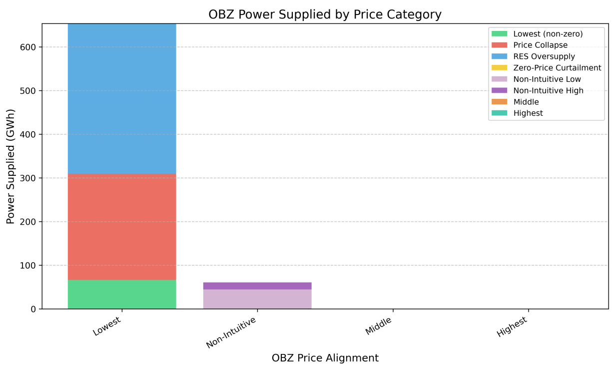
Table 6.13 summarises price-related outcomes under misaligned wind conditions and heterogeneous turbine technologies. Compared to earlier scenarios, the price signals here are shaped not just by wind timing (as in Scenario 2) or turbine efficiency (as in Scenario 3), but by the interaction of both. Under the 2-sided CfD, the mean price is 5.76 €/MWh, slightly lower than in Scenario 3, despite greater wind misalignment. This suggests that desynchronisation dampens price spikes, even when turbines perform unequally. Financial CfD configurations maintain more stable mean prices around 5.10–5.15 €/MWh, with lower variance and standard deviation than the 2-sided CfD, consistent with earlier findings.

A notable difference from Scenarios 1 and 3 is the increase in low-price hours across all financial CfD designs, rising to 594 hours. This reinforces how staggered wind output reduces price convergence and heightens exposure to low-price clearing. At the same time, medium-price hours (11 h) only appear under financial CfD variants, and high-price hours remain absent across all policies, similar to prior scenarios.

The price behaviour in Scenario 4 suggests that while turbine heterogeneity amplifies certain bidding disparities (as shown in Scenario 3), the presence of wind misalignment helps diffuse peak-price clustering. Financial CfD designs continue to suppress volatility but remain sensitive to generator performance and contract allocation.



(a) Price risk frequency in the reference case

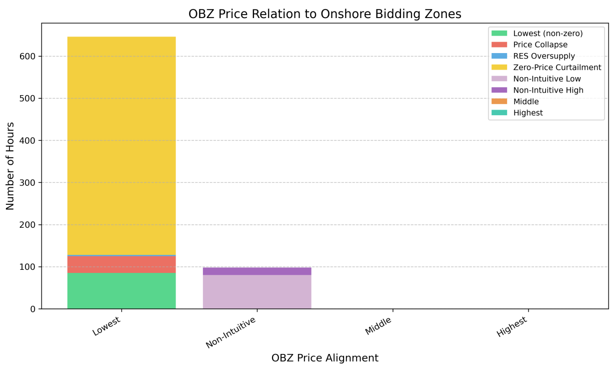


(b) Price risk magnitude in the reference case

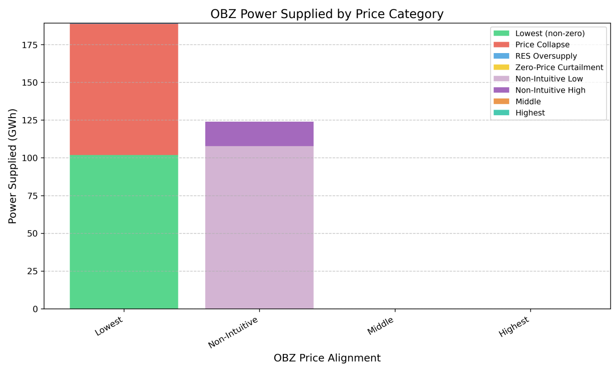
Figure 6.29: Offshore bidding zone price behaviour under Scenario 2

In the reference case, which represents the scenario without any financial support scheme or under a production-based Contract for Difference, power was dispatched in 56 timesteps under the lowest price category. There were no timesteps in either the middle or highest price ranges. Additionally, power was dispatched during 30 timesteps that featured non-intuitive low prices and 18 timesteps with non-intuitive high prices. There were 117 timesteps where a significant drop in market price was observed, and 521 timesteps with excess renewable generation. Complete curtailment occurred in 2 timesteps when the market price was zero. The dispatched energy during these intervals amounted to 66.53 GWh under the lowest price category, 44.63 GWh under non-intuitive low-price conditions, and 16.24 GWh under non-intuitive high-price conditions. During hours with low market prices, 242.50 GWh was dispatched, and 344.45 GWh was dispatched when renewable generation exceeded system demand. No power was dispatched during the zero-price curtailment events.

In the reference case of Scenario 4, the price-risk distribution is similar to that of Scenario 2 but is more distorted. In Scenario 2, all of power is offered into the market, but here, the turbines vary in capacity. As a result, bidding volumes differ across OWFs even under similar wind conditions. Compared to Scenario 1, where all OWFs were identical and bidding was uniform, here we observe greater divergence in dispatch behaviour across the same price intervals. Non-intuitive pricing is also more frequent with 48 instances. The number of sharp price drop events (117 hours) and excess renewable generation hours (521) closely resembles Scenario 2, but the energy dispatched during these events is more unevenly distributed, reflecting unequal turbine performance. Overall, while the absence of CfDs removes strategic withholding, the combination of desynchronised wind and varied turbines still leads to varied dispatch and pricing volatility.



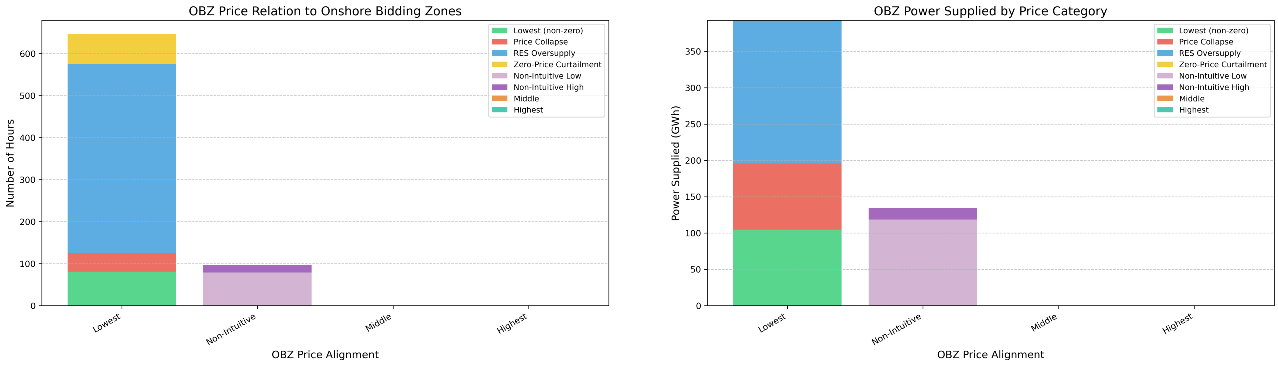
(a) Price risk frequency in the financial CfD with the reference generator as the average dispatch of the OBZ



(b) Price risk magnitude in the financial CfD with the reference generator as the average dispatch of the OBZ

Figure 6.30: OBZ price behaviour under the financial CfD with reference generator as the average dispatch of the OBZ

In the scenario where a financial Contract for Difference is implemented and the reference generator is defined as the average of the dispatched power in the zone, power was dispatched in 85 timesteps under the lowest price category. There were no dispatches under the middle or highest price ranges. Dispatch occurred during 80 non-intuitive low-price hours and 18 non-intuitive high-price hours. The system experienced 40 hours of significantly reduced market prices and 3 hours of excess renewable generation. Complete curtailment occurred during 518 timesteps with zero market price. The corresponding dispatched energy was 101.88 GWh under the lowest price category, 107.71 GWh under non-intuitive low-price periods, and 16.24 GWh during non-intuitive high-price periods. A total of 86.82 GWh was dispatched during low-price conditions, and 0.52 GWh during excess renewable generation.



(a) Frequency of OBZ price categories under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

(b) Magnitude of OBZ price deviations under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

Figure 6.31: OBZ price behaviour under asymmetric financial CfD allocation (nodes 119 and 120 contracted, node 124 uncontracted).

In the case where two wind farms are supported by a financial Contract for Difference and the third operates without one, power was dispatched in 81 timesteps under the lowest price category. No dispatch was recorded in the middle or highest price categories. Power was dispatched during 79 non-intuitive low-price hours and 18 non-intuitive high-price hours. There were 44 hours of low market prices and 450 hours with excess renewable generation. Complete curtailment was observed in 72 timesteps during zero market price. The dispatched power included 104.48 GWh under the lowest price category, 118.42 GWh during non-intuitive low-price conditions, and 16.24 GWh during non-intuitive high-price conditions. During hours with reduced prices, 91.18 GWh was dispatched, while 197.19 GWh was dispatched during excess renewable generation.

Scenario 4, which combines misaligned wind profiles with heterogeneous turbine technologies, introduces the most complex price dynamics across all scenarios. Compared to Scenario 1 (homogeneous turbines with aligned wind), price risks are amplified by the combined effects of temporal desynchronisation and varying turbine output. Unlike Scenario 2, where misalignment alone drove price distortions, Scenario 4 reveals that turbine heterogeneity contributes further to non-intuitive pricing. In particular, the average-reference mechanism becomes less representative under these conditions. Since higher-performing turbines contribute disproportionately to total output, they have a stronger influence on the reference signal. This can unintentionally disadvantage lower-output turbines, which are more likely to be penalised under the clawback mechanism, not because of strategic underperformance, but due to inherent capacity differences. Thus, turbine diversity introduces structural imbalances into the reference-based CfD design.

6.4.2 Volume Metrics & General Characteristics

Table 6.14: Volume risk metrics under Misaligned Wind and Heterogeneous Turbine Technology, No Offshore Electrolyser

Metric	**Production-Based CfD**	**Financial CfD**				
	2-Sided CfD	**Ref = Node Avg**	**Ref = Node 98**	**Only Node 98 CfD**	**No CfD on Node 98**	**No CfD on Node 103**
Congested HVDC (h)	625	561	561	561	561	566
Capacity calculation (h)	345	0	0	0	0	21
Capacity allocation (h)	543	2	2	2	2	87

Volume risks in Scenario 4 continue the pattern observed in Scenarios 2 and 3, but with added nuance. As in previous financial CfD cases, capacity calculation and allocation risks are largely suppressed.

Compared to Scenario 2, which also had misaligned wind but used identical turbines, Scenario 4 shows fewer capacity calculation risks under the 2-sided CfD (345 hours instead of 427). This reduction is because the turbines in Scenario 4 produce different amounts of power, which naturally spreads out the total generation and reduces the chance of all farms peaking at the same time. However, compared to Scenario 3, total congestion remains similarly high, confirming that even when output is staggered over time, transmission limits remain a hard constraint.

Table 6.15: General characteristics under Misaligned Wind and Heterogeneous Turbine Technology, No Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Total wind generation (GWh)	714.34	313.16	313.16	313.16	313.16	475.35
Export at 0 price (GWh)	586.96	87.02	87.02	87.02	87.02	273.39
Revenue Farm 1 (€M)	1.20	0.98	1.43	1.26	1.50	0.90
Revenue Farm 2 (€M)	2.14	0.77	1.22	1.29	0.77	0.74
Revenue Farm 3 (€M)	2.37	1.12	1.57	1.64	1.12	1.93
Mean Rev Farm 1 (€/MWh)	1614.69	1319.07	1920.00	1692.22	2019.40	1214.81
Mean Rev Farm 2 (€/MWh)	2879.29	1034.13	1635.06	1734.46	1034.13	995.49
Mean Rev Farm 3 (€/MWh)	3187.24	1510.03	2110.96	2210.37	1510.03	2593.50

The general characteristics confirm that misaligned wind and varied turbine performance lead to uneven revenue outcomes. In the 2-sided CfD case, total generation is slightly higher than in Scenario 3, but much of it is exported at zero price, mainly from the high-capacity turbine at Wind Farm 2. Under financial CfDs, revenues are more stable, but clear biases remain. Wind Farm 2 earns the most because it has the most efficient turbine, while Wind Farm 3 also performs well thanks to its stronger grid connection. In asymmetric CfD setups, these advantages are even more noticeable. Unlike Scenarios 1 and 2, where revenue differences were caused by either location or timing, Scenario 4 shows both effects working together. Wind farms with both favourable turbine performance and advantageous timing tend to benefit the most under uniform CfD schemes, while others are left at a disadvantage. This outcome reveals a key limitation: CfD structures that do not account for technological or locational diversity may unintentionally concentrate benefits among a few assets. While this may appear efficient from a system-level cost perspective, it raises concerns about fairness, long-term investment signals, and coordination in shared infrastructure settings.

6.5 Section 5: Aligned Wind, Same Turbine Technology, Offshore Electrolyser on a node

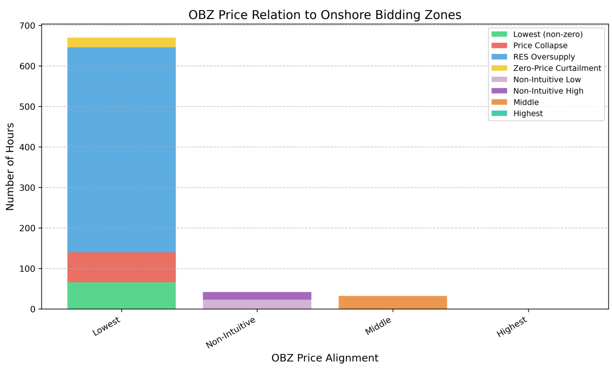
This scenario considers aligned wind conditions across all wind farms, with identical turbine technology deployed at each location. An offshore electrolyser is introduced at node 120, which is also the location of Offshore Wind Farm 2. The electrolyser is intended to be a flexible demand agent within the OBZ, utilising wind energy as per the electricity prices in the zone. The table below presents the outcomes under various policy configurations. This section explores how the presence of a flexible demand agent affects the price formation, bidding behaviour and revenue trends under different CfD configurations.

6.5.1 Price Metrics

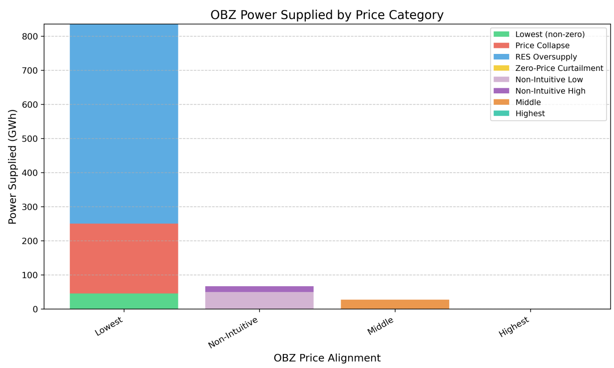
Table 6.16: Price risk metrics under Aligned Wind and Same Turbine Technology, Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Mean price (€/MWh)	6.60	8.57	8.57	5.10	8.57	8.50
Std Dev	15.28	16.15	16.15	12.36	16.15	16.16
Variance	2.31	1.88	1.88	2.42	1.88	1.90
Low price hours (h)	599	633	633	633	633	615
– Zero price (h)	530	522	522	522	522	523
– Non-zero price (h)	66	111	111	111	111	92
Medium price hours (h)	30	32	32	32	32	60
High price hours (h)	0	0	0	0	0	0
Non-intuitive price (h)	116	78	78	78	78	66
– Zero price (h)	74	1	1	1	1	0
– Non-zero price (h)	42	77	77	77	77	66
Price delta (bids) (h)	0	165	165	198	165	124

The price metrics in Scenario 5 show how the presence of an offshore electrolyser affects price formation under aligned wind and uniform turbine conditions. Across all financial CfD variants, average market prices increase notably, rising to 8.57 €/MWh in most cases, compared to 6.60 €/MWh under the 2-sided CfD. This suggests that the electrolyser's role as a flexible consumer helps absorb excess supply, easing price suppression typically seen in high-export scenarios. Medium-price hours increase across all financial CfDs, while low-price hours remain elevated, though slightly reduced in the 'Only Node 98 CfD' case. Medium-price hours refer to time steps when the price in the offshore bidding zone (OBZ) converges with that of the middle-priced onshore zone. However, the increased frequency of price change events reflects increased strategic bidding around the reference generator. In summary, the electrolyser helps support price levels and reduces curtailment-driven price collapse.



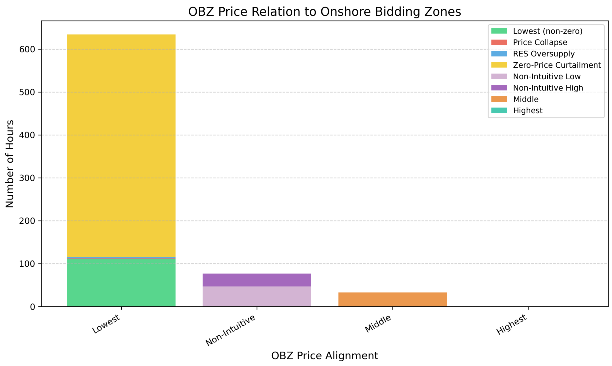
(a) Price risk frequency in the reference case



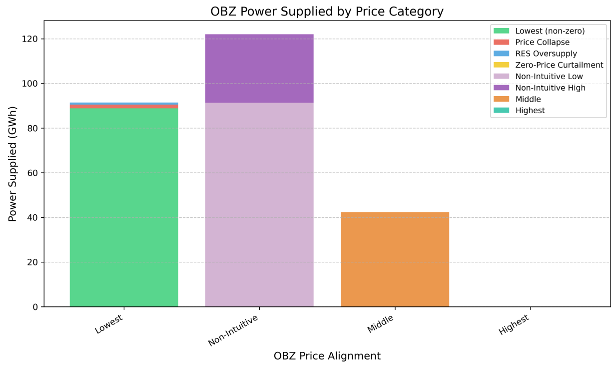
(b) Price risk magnitude in the reference case

Figure 6.32: Offshore bidding zone price behaviour under Scenario 5

In the reference case, dispatch under the lowest price condition occurred 66 times, with a total dispatched power of approximately 45.74 GWh. There were 32 instances of middle-range prices, resulting in 27.34 GWh of dispatch. There were no instances of high prices. Dispatch during intervals with a mismatch between market price and expected price due to network effects occurred 23 times on the lower side and 19 times on the higher side, with 49.79 GWh and 16.63 GWh dispatched respectively. Dispatch under very low pricing conditions resulting from oversupply occurred 74 times, contributing 204.52 GWh. During hours when available renewable energy exceeded system demand and capacity, the dispatched power amounted to 585.32 GWh over 506 hours. Complete curtailment of wind farm output at zero market price occurred 24 times, though no energy was dispatched in these periods.



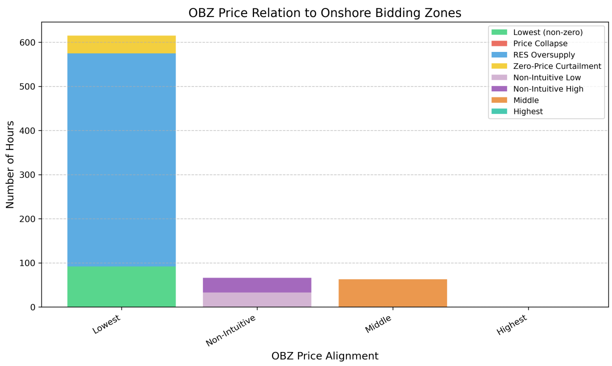
(a) Price risk frequency in the financial CfD with the reference generator as the average dispatch of the OBZ



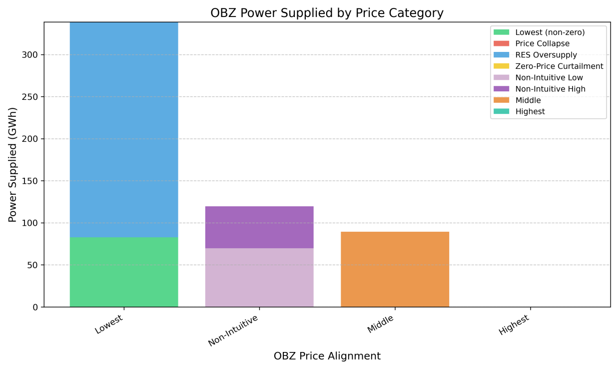
(b) Price risk magnitude in the financial CfD with the reference generator as the average dispatch of the OBZ

Figure 6.33: Offshore bidding zone price behaviour under Scenario 5

Under the financial CfD with a reference generator based on the average of zonal dispatch, 111 intervals were identified with the lowest price, during which 88.83 GWh of power was dispatched. 33 intervals occurred in the middle price range, totalling 42.27 GWh. No high price intervals were observed. There were 47 and 30 intervals of non-intuitive low and high pricing respectively, with associated dispatch volumes of 91.30 GWh and 30.69 GWh. Instances of low price caused by extreme supply-demand imbalances occurred once, with 1.63 GWh dispatched. Instances where available renewable energy exceeded system limits resulted in 0.93 GWh of dispatch over four occurrences. Complete curtailment of wind farm output at zero market price occurred in 518 intervals, with no power dispatched in those hours. The total power dispatched across all categories in this case was approximately 527.51 GWh.



(a) Frequency of OBZ price categories under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.



(b) Magnitude of OBZ price deviations under financial CfD in nodes 119 and 120, with node 124 exposed to market prices.

Figure 6.34: OBZ price behaviour under asymmetric financial CfD allocation (nodes 119 and 120 contracted, node 124 uncontracted).

In the configuration where two wind farms operate under a financial CfD and the third is exposed to the market, there were 92 intervals of lowest market price, accounting for 82.79 GWh of dispatch. Middle pricing intervals occurred 63 times, during which 89.35 GWh of power was dispatched. There were no intervals with high prices. Non-intuitive price occurrences were recorded 33 times each for both lower and higher pricing deviations, resulting in 69.81 GWh and 49.86 GWh of dispatch, respectively. No intervals were observed with extremely low pricing due to system imbalance. In hours with excessive renewable energy relative to demand and network limits, 255.80 GWh of power was dispatched over 483 intervals. Full curtailment of wind farm output at zero market price occurred in 40 intervals, with no dispatch recorded during these hours.

Scenario 1 also featured aligned wind and identical turbines but lacked an offshore electrolyser. The price dynamics in Scenario 5 after the addition of an offshore electrolyser show a distinct shift. The addition of the electrolyser leads to a reduction in curtailment-related waste and enables higher dispatch volumes during low-price and oversupply hours. In the reference case, for instance, Scenario 5 records more dispatch during oversupply (585.32 GWh) than in Scenario 1, where such flexibility was missing. The financial CfD with average reference also shows an increase in low- and mid-price interval dispatch of over 130 GWh, with non-intuitive pricing somewhat stabilised. Importantly, the electrolyser moderates extreme curtailment events without entirely eliminating them, as seen in the still-high zero-price curtailment counts. Asymmetric configurations further highlight the role of market exposure. Uncontracted farms are allowed to take advantage of mid-priced hours more effectively than in Scenario 1, where such intervals were rare. Scenario 1 exhibited sharp dispatch distortions and higher price divergence. However, Scenario 5 illustrates how demand-side flexibility can smooth price outcomes and enhance the system's ability to absorb surplus renewable generation.

6.5.2 Volume Metrics

Table 6.17: Volume risk metrics under Aligned Wind and Same Turbine Technology, Offshore Electrolyser

Metric	Production-Based CfD	Financial CfD				
	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Congested HVDC (h)	–	523	523	523	523	523
Capacity calculation (h)	311	0	0	0	0	6
Capacity allocation (h)	456	2	2	2	2	17

Table 6.18: Comparison of curtailed volume (hours and MWh) due to volume risks in Scenario 1 and 5

Volume Risk Type	Scenario 1		Scenario 5	
	Hours	MWh	Hours	MWh
Capacity Allocation	543	539,840.55	456	264,843.91
Capacity Calculation	394	507,246.61	311	402,528.45

Table 6.18 compares the severity of volume risks between Scenario 1 (no electrolyser) and Scenario 5 (with an offshore electrolyser). Both curtailment hours and total curtailed energy are presented to highlight not just the frequency but also the magnitude of these constraints.
The results demonstrate a notable improvement in Scenario 5. Capacity allocation curtailment drops from 543 hours and 539.8 GWh in Scenario 1 to 456 hours and 264.8 GWh in Scenario 5. Similarly, capacity calculation curtailment falls from 394 hours and 507.2 GWh to 311 hours and 402.5 GWh. These reductions confirm that the presence of the offshore electrolyser, which acts as a flexible load at node 120, helps absorb excess renewable generation that would otherwise be curtailed.

While the number of risk hours is still substantial, the halving of curtailed energy under capacity allocation indicates that the electrolyser is effective at shaving off high-volume peaks. This makes Scenario 5 efficient in terms of energy use and also more resilient to curtailment-driven economic losses. In contrast to Scenario 1, where high output across all OWFs leads to system-wide curtailment, Scenario 5 benefits from local absorption at critical moments, reducing system strain without introducing price distortions.

These findings underscore the value of co-locating demand-side flexibility, like electrolysers, with renewable generation.

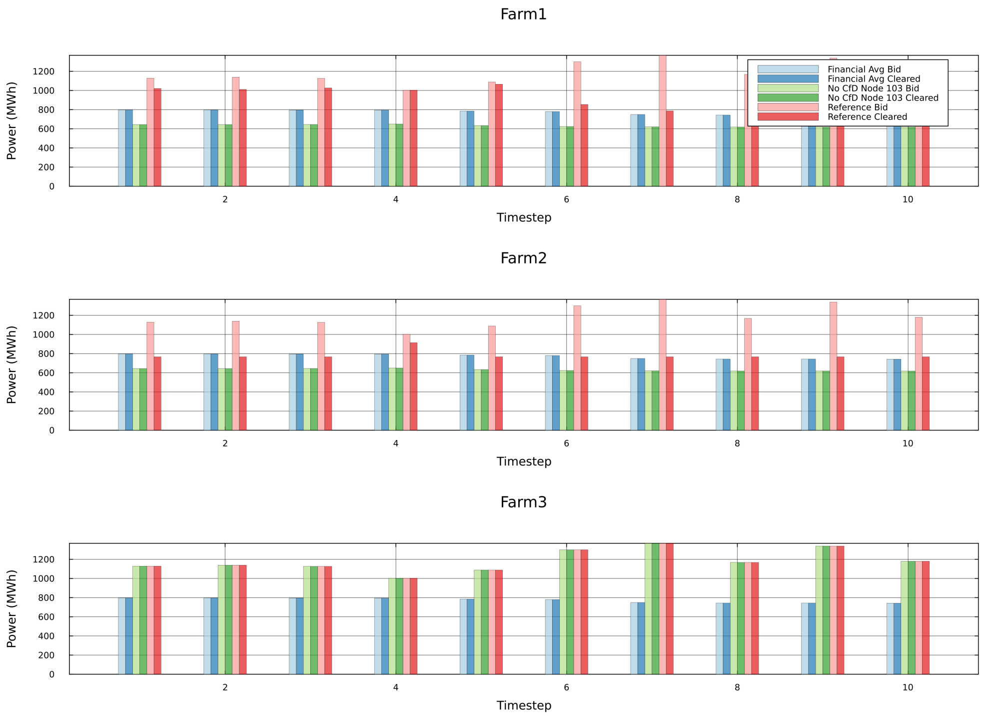


Figure 6.35: Bid and cleared volumes for three offshore wind farms across 10 time steps under different CfD policies in Scenario 5

The introduction of financial CfD leads to a reduction in volume-related risks, consistent with observations from previous scenarios. These volume risks are lower in this scenario, with the introduction of an offshore electrolyser, as compared to the other scenarios. The wind farm located at node 124 continues to benefit from a higher volume of cleared power when it is not covered by a financial CfD. When the financial CfD is applied, the wind farms begin to align their bidding behaviour again, similar to the first scenario. However, the main impact is observed in price formation, with a noticeable increase in the number of intervals where prices converge at higher levels.

6.5.3 General Characteristics

Table 6.19: General characteristics under Aligned Wind and Same Turbine Technology, Offshore Electrolyser

Metric	**Production-Based CfD**	**Financial CfD**				
	2-Sided CfD	**Ref = Node Avg**	**Ref = Node 98**	**Only Node 98 CfD**	**No CfD on Node 98**	**No CfD on Node 103**
Total wind generation (GWh)	929.33	255.64	255.64	313.16	313.16	547.60
Export at 0 price (GWh)	789.83	2.55	2.55	87.02	87.02	255.80
Revenue Farm 1 (€M)	1.03	0.96	1.43	1.13	2.40	0.78
Revenue Farm 2 (€M)	3.20	0.96	1.43	2.40	0.96	0.78
Revenue Farm 3 (€M)	3.20	0.96	1.43	2.40	0.96	3.22
Mean Rev Farm 1 (€/MWh)	1394.54	1295.20	1920.00	1522.97	3233.42	1055.92
Mean Rev Farm 2 (€/MWh)	4298.69	1295.58	1920.37	3233.79	1295.58	1056.50
Mean Rev Farm 3 (€/MWh)	4299.60	1295.58	1920.37	3233.79	1295.58	4329.17

The results show clear patterns in how different CfD configurations shape generation and revenue outcomes. Total wind generation is highest under the 2-sided CfD, but this also results in the largest export at zero price, indicating that surplus generation often cannot capture market value. In contrast, financial CfD setups lead to lower total generation, due to more strategic bidding aimed at aligning with the reference generator and reducing clawback.

6.6 Cross-Scenario Results

The comparison across the five scenarios reveals how wind alignment, turbine heterogeneity, the presence of an offshore electrolyser and CfD policy structure interact to shape market performance, dispatch outcomes, and systemic stress. The price metrics are compared under a financial CfD with the reference as the average of the dispatch in the OBZ, for all scenarios. The volume metrics are compared for the case of one OWF being uncontracted, while the other two, in the OBZ, are under a financial CfD.

6.6.1 Price metrics comparison

Table 6.20: Price Risk Comparison under Financial CfD with Average Reference Generator (Case 4)

Scenario	Avg Price (€/MWh)	Hour Count				Dispatch Volume (GWh)			
		Lowest	Middle	Price Collapse	Non-Intuitive	Lowest	Middle	Collapse	Non-Intuitive
S1	6.61	88	2	28	59	108.32	2.07	68.34	42.16
S2	4.56	63	0	47	113	83.32	0.00	100.32	141.04
S3	5.91	126	3	33	59	116.34	0.00	71.62	75.77
S4	5.10	85	0	40	98	101.88	0.00	86.82	123.94
S5	8.57	111	33	1	77	88.83	42.27	1.63	121.99

Table 6.20 summarises the price risk metrics under Case 4, where a financial CfD is applied using the average dispatch of the OBZ as the reference generator. It highlights how different structural conditions across scenarios affect hourly pricing categories and the corresponding dispatch volumes.

The comparison across scenarios reveals how wind profile, turbine efficiency, and financial CfD design interact to shape price formation and dispatch incentives. In Scenario 1, price collapse and RES oversupply are almost eliminated under the financial CfD, but this is achieved through 518 hours of complete curtailment. Average prices rise to 6.61 €/MWh, while non-intuitive price events persist in 59 hours. Dispatch during these events remains limited, indicating that OWFs cut generation to match the reference profile. This confirms that incentives override system needs, leading to stable prices but strategic distortions.
Scenario 2 shows a different dynamic. Misaligned wind lowers the average price to 4.56 €/MWh, the lowest across all scenarios. However, price collapse occurs in 47 hours even under the financial CfD, and non-intuitive pricing is frequent. Dispatch volumes during these hours are higher than in Scenario 1, showing that OWFs do not fully suppress output to follow the reference. The result is lower prices but a more volatile operation. Scenario 3 increases average prices to 5.91 €/MWh and also shows 518 hours of curtailment. The financial CfD reduces collapse and oversupply. Scenario 4 produces similar patterns, with average prices of 5.10 €/MWh and high curtailment again used to suppress surplus. Non-intuitive dispatch volumes remain large, showing that wind farm output is still strategically adjusted.
Scenario 5 records the highest average prices at 8.57 €/MWh. This is linked to the electrolyser, which reduces the need for curtailment to avoid collapse. Yet, 518 hours of curtailment still occur, confirming that bidding strategies remain focused on matching the reference. Across all scenarios, the financial CfD with an average reference leads to deliberate reductions in generation. This behaviour reduces market volatility but does not always align with efficient system operation. The same incentive

structure produces different levels of distortion depending on wind alignment and technology, showing that policy design must account for operational diversity.

6.6.2 Volume metrics comparison

Table 6.21: Volume Curtailment and Production Reduction under No CfD on Node 103 Configuration

Scenario	Capacity Allocation Curtailment (GWh)	Capacity Calculation Curtailment (GWh)	Production Reduction (%)
S1	11.19	4.07	3.11%
S2	73.38	27.92	15.79%
S3	11.54	4.36	3.04%
S4	54.86	26.43	14.60%
S5	1.46	2.97	0.80%

Table 6.21 compares volume curtailment across all five scenarios under the No CfD on Node 103 configuration. This asymmetric CfD design consistently reduces both capacity allocation and capacity calculation curtailment relative to other cases. However, the extent of the reduction varies depending on system structure.

The lowest curtailed volumes occur in Scenario 5, where capacity allocation and calculation curtailment drop to just 1.5 GWh and 3.0 GWh, respectively. This suggests that the presence of the offshore electrolyser provides a strong relief mechanism for the system, even when one wind farm operates without a CfD. Similarly, Scenarios 1 and 3 (both with aligned wind) show curtailed volumes under 12 GWh for capacity allocation and under 4.5 GWh for capacity calculation, indicating that this scheme performs best when wind production is synchronised and predictable.
In contrast, Scenarios 2 and 4, with misaligned wind profiles or turbine heterogeneity, exhibit higher curtailed volumes under the same CfD configuration (73–115 GWh for capacity allocation and 26–28 GWh for capacity calculation).

The OWF at Node 124, which is not covered by a CfD, remains fully exposed to market prices and can dispatch more power than the CfD-covered wind farms. Its favourable grid connection further amplifies this advantage, often forcing the CfD-contracted OWFs to curtail their output to accommodate the high dispatch volumes from Node 124. These behaviours are especially prominent in average-reference schemes, where wind farms collectively curtail to match a benchmark, even during high-demand periods.

6.6.3 Role of the Reference Generator in Driving Operational Inefficiencies

A consistent finding across all scenarios is the central role of the reference generator in shaping wind farm behaviour and driving operational inefficiencies under financial CfDs. In all cases analysed, the financial CfD design uses the average dispatch across all OWFs in the OBZ as the reference. This reference directly determines revenue outcomes through the clawback mechanism: wind farms are financially rewarded when they dispatch more than the reference and penalised when they fall short.

This incentive structure creates a strategic dynamic in which each OWF attempts to outperform the average dispatch. However, since all OWFs face the same incentive, and the reference is itself the average of their collective actions, they tend to converge toward a common dispatch level. This leads to a stable but suboptimal equilibrium, where all OWFs limit output to avoid the risk of falling below the reference and being penalised. The result is frequent strategic self-curtailment, even during hours when the grid can accommodate more renewable generation.

These findings highlight the importance of reference selection in CfD policy design. Using a zonal average as a benchmark induces symmetric behaviour that erodes the value of locational advantages and leads to uniform curtailment. More granular, performance-sensitive references, whether node-specific or dynamically updated could mitigate these effects. Without such refinements, financial CfDs risk introducing contract-driven operational inefficiencies that offset their price-stabilisation benefits.

7 | Discussion

This chapter continues elaborating the results from the previous chapter, while putting it in the context of the literature discussed in Chapters 2 and 3. The first section, Sections 7.1 - 7.5, focuses on the model-specific outcome and Section 7.6 outlines some of the limitations of the model.

7.1 Results Overview

The results across all scenarios confirm that price and volume risks are deeply embedded in offshore bidding zones (OBZs), especially under high renewable penetration. In the absence of policy support, offshore wind farms (OWFs) are exposed to severe price volatility and curtailment risks, without being able to proactively shape their revenues. Due to high renewable generation levels, there is system-wide congestion and low-price saturation caused by cannibalisation.

7.1.1 Performance of Production-Based CfDs

Production-based CfDs address some aspects of price risk by guaranteeing a payment per unit of dispatched energy. However, the revenue still depends on physical dispatch, which remains tied to wind availability and network constraints. Therefore, some periods yield no income due to curtailment, while others yield excessive payments even when the market price is zero. Critically, these designs do not respond to price signals and offer no mechanism to encourage OWFs to adapt their output to market conditions. Volume risks are fully passed on to the producer, as the incentive is always to bid the full available capacity regardless of system need. Capacity calculation and allocation issues frequently result in curtailed output.

7.1.2 Effectiveness and Limitations of Financial CfDs

Financial CfDs, in contrast, significantly reduce both price volatility and volume-related risks. They achieve this by decoupling revenue from physical dispatch and anchoring it to a strike price linked to a reference generator. This design removes the incentive to overbid and thus resolves many curtailment risks observed under production-based designs. Notably, price collapse and renewable oversupply events almost vanish under these schemes.
However, these benefits are achieved through behavioural distortions. Wind farms often curtail themselves partially or entirely, for prolonged periods (up to 518 hours in several scenarios) to match the output of the reference generator. This self-curtailment suppresses system-level stress but does so at the cost of operational efficiency. While curtailment risk disappears numerically, it is replaced by voluntary withholding that is incentivised by policy design rather than system need.

Residual risks persist as well. Non-intuitive pricing, where OBZ prices diverge from expected zonal trends, remains common. These are especially prominent when one OWF is left uncovered by a CfD, resulting in conflicting incentives and uncoordinated bidding behaviour.

7.1.3 Locational and Technological Distortions

The spatial layout of the OBZ further skews outcomes. One OWF in the model, located at Node 124, consistently receives more cleared volume and revenue due to its favourable grid connection: it is connected to a higher-priced onshore node and benefits from a larger export capacity. This locational advantage leads to a persistent revenue gap when that wind farm is not covered by a CfD. When all OWFs are symmetrically contracted under a financial CfD, this distortion is partially mitigated through enforced bid uniformity.

Technological heterogeneity introduces similar distortions. A more efficient turbine, with better performance during high-demand hours, consistently earns more revenue when OWFs use different turbine technologies. When this turbine is included in the reference generator calculation, it raises the benchmark, causing lower-performing OWFs to under-deliver relative to the reference and receive reduced or even negative payments. This creates a systematic merit order in revenue distribution that favours turbines capable of delivering high output during peak-price periods.

7.1.4 Combined Effects and Systemic Trends

The combination of wind profile misalignment and technological diversity (as seen in Scenario 4) results in layered risk exposure and increased dispersion in outcomes. Financial CfDs suppress extreme events, but do so by flattening operational behaviour across OWFs, often in ways that ignore their physical capabilities. In scenarios where flexibility is added, such as the introduction of an offshore electrolyser in Scenario 5, the system absorbs more power, and prices stabilise at higher levels. Yet, even in this case, bidding distortions persist as wind farms continue to curtail output to match the reference.

In summary, financial CfDs are highly effective at reducing headline price and volume risks. However, they do so by shifting the risk landscape rather than eliminating it.The operational behaviour of wind farms under financial CfDs can trigger certain dispatch distortions, particularly when the claw-back mechanism is based on average zonal dispatch. This design unintentionally encourages strategic self-curtailment, as OWFs align their bids to minimise exposure relative to the average. Moreover, when turbine performance differs, the use of a common reference introduces a technology-driven bias. Turbines that produce more energy at high price periods dominate the reference, disadvantaging others. In such cases, a reference linked to technology class or turbine-specific benchmarks would better reflect the operational diversity.

An alternative configuration, where each OWF is assigned its own OBZ, would fundamentally change the market dynamics. With each farm clearing independently, the reference would become farm-specific, eliminating the need for inter-farm coordination and removing the distortions associated with average-based referencing. However, this comes at the cost of losing locational coordination benefits and complicates system-wide optimisation, as market signals become fragmented and grid effects become more localised.

7.2 Implications of CfD Design in an OBZ

7.2.1 Inherent risk landscape of OBZs

OBZs are structurally exposed to both price and volume risks, especially under high shares of renewable generation. The lack of local demand and reliance on HVDC interconnectors make the OWFs vulnerable to systemic constraints. There are two broad categories of risks pertinent in an OBZ environment: price and volume risks.

There is a significant flat price risk inherent in the OBZ, primarily driven by the structure of flow-based market coupling (FBMC) and the high penetration of wind generation. As observed in the model, prices in the OBZ frequently collapse to zero or near-zero levels due to the saturation of low-marginal-cost wind energy. During periods of high offshore generation, the OBZ is unable to export all its power due to limited HVDC transmission capacity, leading to local oversupply. Since the OBZ rarely sets the marginal price, it inherits price signals from onshore zones.

Volume risk, on the other hand, is driven by structural congestion. OWFs are subject to curtailment whenever export constraints bind. One of the reasons is through explicit capacity allocation, where other flows are deemed to be socially optimal. The other is through congestion in the HVDC lines, which calls for curtailment from the wind farms deemed as capacity calculation risk. The model shows that this occurs frequently even in scenarios with staggered wind profiles, highlighting that time diversity in production alone cannot fully eliminate curtailment risk. Because OWFs have limited or no internal demand and are entirely dependent on cross-zonal exchange to realise value, they face curtailment not only during system stress but even during normal conditions when zonal prices are unfavourable.

Together, these factors define the baseline risk profile. OWFs in the OBZ are vulnerable to low or zero prices during high output periods and face export constraints that result in curtailed production. In the absence of targeted policy intervention, this landscape leaves producers exposed to significant revenue uncertainty, even when physical conditions are favourable. The severity of these risks depends not just on aggregate wind production, but also on the network topology.

7.2.2 Effectiveness of CfD Designs

The model confirms what has been widely observed in literature, that CfD mechanisms are powerful tools for derisking offshore wind investments. Both production-based and financial CfDs stabilise revenue in different ways, but their effectiveness and their limitations become clearer when tested in the OBZ environment.

In line with previous studies (Neuhoff, Held, Ragwitz, & Schwenen, 2016), the production-based CfD protects against price volatility by guaranteeing a fixed revenue per MWh dispatched. In the model, this protects wind farms from the frequent price collapses observed in the OBZ. However, because revenues are still tied to volume, wind farms are incentivised to maximise output in every hour, regardless of system needs or constraints. This leads to increased curtailment due to capacity allocation and capacity calculation limits. These volume risks can eliminate revenue in congested hours, even when strike prices are high.

Financial CfDs address this trade-off differently. Instead of linking revenue to volume, they stabilise income through fixed payments and clawback adjustments tied to a reference generator. In your model, this reduces the volatility of realised revenues and eliminates most exposure to extreme price events like oversupply and collapse. It is stated by (D. M. Newbery, 2016), that financial CfDs are shown to shield producers from market price fluctuations without incentivising inefficient dispatch.

But the model reveals that financial CfDs introduce a disconnect between system conditions and generator behaviour. In many scenarios, wind farms curtail output voluntarily, not due to congestion, but to avoid triggering clawbacks. This behaviour is consistent across different reference structures (node-based or zonal averages), suggesting that the distortion is structural, not circumstantial. From the system's perspective, this leads to inefficient dispatch, reduced utilisation of low-cost renewables. The bidding behaviour is decoupled from the marginal cost. This means that the wind farm strategically curtails output based on the expected revenues, despite having near-zero marginal costs. This disconnect undermines the merit-order principle and results in dispatch patterns that are no longer cost-reflective, a distortion that is rarely addressed in existing CfD literature.

While CfDs achieve their primary goal of securing investor confidence through stable revenues, there are unintended consequences of their design that are highlighted by the model. Production-based CfDs suppress price risk but exacerbate volume uncertainty. Financial CfDs eliminate both but introduce strategic curtailment and weaken the market's ability to reflect real-time conditions. The findings suggest that CfD design must evolve to balance risk coverage with incentives that preserve dispatch efficiency and system responsiveness.

7.2.3 Distortions introduced by CfD reference structure

Recent literature (Schlecht et al., 2024) categorises reference generator options for financial Contracts for Difference (CfDs) into several types, including weather-based models, aggregates of real physical assets, bidding zone averages, and base-profile references. In this thesis, the reference designs tested correspond primarily to two categories: (i) a fixed subset of real offshore wind farms (e.g., a single node), and (ii) an average output profile across all OBZ-connected wind farms. While these methods are implementable and commonly proposed in policy designs, the results from the model show that both options introduce a basis risk into the CfD design.

When a node-based reference is chosen, particularly one tied to a wind farm with favourable wind conditions or grid access, the other farms are exposed to a location-driven basis risk. Their production patterns deviate from the reference due to geographic or technological differences, resulting in systematic clawbacks. In the average-based reference case, farms are incentivised to align their output closely with the collective mean. This removes price volatility and improves predictability, but creates a new basis risk. OWFs whose natural profiles differ from the average (due to misalignment or technology) are forced to curtail or overproduce against their technical optimum. In both cases, the basis risk is financial rather than physical, but it leads to observable changes in dispatch behaviour that deviate from what would occur under marginal cost-based bidding.

7.2.4 Locational and technology distortions due to financial CfD designs

Locational and technological characteristics of OWFs significantly affect market outcomes under financial CfD schemes. While CfDs are designed to hedge against price volatility, they do not neutralise the operational advantages of favourable locations or superior technology. Under uniform pricing mechanisms, generators at nodes with better grid connectivity or access to higher-priced zones will realise more value per MWh dispatched (Neuhoff et al., 2016). These effects persist under financial CfDs, as confirmed in this model.

In the OBZ configurations simulated, OWFs located at node 124 consistently earned more revenue when not covered by a CfD. This was due to structural advantages rather than strategic bidding. A stronger HVDC connection and proximity to a higher-priced zone helped the wind farm to dispatch more power in the market. This effect will be somewhat reduced in a larger coupling zone, due to more zones participating in the market. In the model, there are three onshore zones, which amplify the effects. However, the principle will remain the same. When financial CfDs were introduced, this locational advantage was partially mitigated by forcing farms to coordinate bids. However, basis risk still emerged where the reference generator did not reflect locational heterogeneity, leading to asymmetric clawbacks.

A similar distortion emerges from turbine heterogeneity. In scenarios with misaligned wind and differing technologies, the wind farm with the best-performing turbine consistently earned more. This is because it produced more power during high-price hours. This created a "merit order" within the OBZ, based not on cost efficiency but on technical output capacity during system-critical periods. These results align with concerns raised in literature (Schlecht et al., 2024), suggesting that uniform

CfD designs in heterogeneous systems can cause structural imbalances unless appropriately calibrated.

7.3 Limits of Strategic Behaviour Under Real-World Uncertainty

An important consideration when interpreting the model results is whether OWFs would engage in similarly distortive behaviour in real-world market settings. In the model, wind farms are assumed to have perfect foresight over future prices and system outcomes, allowing them to make strategic ex ante decisions, particularly under financial CfDs, where the reference generator structure incentivises coordinated or curtailed bidding. However, this level of certainty is unlikely to exist in practice.

In real markets, multiple layers of uncertainty constrain such precise optimisation. These include uncertainty in wind forecasts, which directly impact generation volume; uncertainty in market prices, which are shaped by bids from other market participants; and broader uncertainties from grid congestion, reserve requirements, or balancing actions. As a result, wind farms cannot be sure how their own bids will influence the reference price, or whether strategic curtailment will ultimately yield higher net revenues.

This implies that the type of coordinated curtailment behaviour seen in the model, where OWFs perfectly align their bids to maximise net CfD payouts, may be harder to implement in reality. Instead, operators are more likely to act based on expected marginal gains or losses, balancing the probability of clawbacks against lost market revenue. In scenarios where expected revenues are near the strike price, the decision space becomes even narrower. Thus, real-world strategic bidding would require sophisticated forecasting tools and a strong understanding of system dynamics, which may only be accessible to the largest or most integrated players.

Moreover, the presence of multiple actors in competitive OBZ environments introduces game-theory complexity. Individual wind farms may find it difficult to predict others' strategies, reducing the feasibility of coordinated behaviour. This reinforces the importance of careful CfD design. Under high uncertainty, minor differences in contract structure could lead to vastly different outcomes, not only for individual revenue streams but for system-wide dispatch efficiency.

Ultimately, while the model highlights the theoretical potential for strategic distortion, the extent to which this plays out in real-world settings will depend on market transparency, the sophistication of forecasting and bidding tools, and the regulatory framework governing offshore bidding zones.

7.4 Recommendation to Policy Makers

This study highlights several critical insights into how the design of CfDs influences the operational and economic behaviour of OWFs within an OBZ. These insights align with recent literature, and the findings suggest directions for improving CfD policies as renewable energy penetration increases.
The model demonstrates that even when the OWFs possess identical installed capacity, locational and technological advantages can lead to a disparity in the revenue distribution of the OWFs. The disparity arises due to the inherent nature of the flow-based dispatch, which favours certain nodes and the ability of some turbines to produce more power during high-demand periods. As mentioned by (D. Newbery, 2021), the use of average or reference benchmarks without adjustment can skew incentives, leading to inefficient dispatch. Location-based referencing or location-aware strike prices should be used to nullify locational basis risk. While technology-neutral reference generators will lead to fairer outcomes.

The results from Scenario 5 highlight how flexible demand-side solutions like offshore electrolysers can play a key role in reducing curtailment and stabilising OBZ prices. These offshore electrolysers help absorb excess wind, which would otherwise be curtailed due to capacity allocation, and in some cases also set the price in the OBZ. This aligns with (Agency, 2021) which suggests a co-located flexible demand agent to better integrate renewables to the system. The policymakers can also encourage priority grid access (ENTSO-E, 2024b) to ensure offshore electrolysers play an active role in the OBZ framework.

In addition, the emergence of strategic bidding behaviour under financial CfDs, where OWFs co-ordinate to minimise clawback exposure, demonstrates the need to anticipate and manage systemic market effects. This behaviour transforms the OBZ into an interconnector in certain hours, affecting price formation not only locally but also in adjacent zones. (Hogan, 2014) mentions that misaligned contract incentives lead to system-wide inefficiencies. In some cases, the clawback if known to wind farms can be internalised as opportunity cost, leading to distortions in the other market segments as well (Schittekatte et al., 2024). To mitigate such outcomes, policymakers should introduce enhanced scenario-based modelling to test future CfD designs for behavioural responses from the OWF and overall system efficiency.

Transmission System Operators:

This study suggests a more active role in identifying strategic self-curtailment patterns driven by policy rather than physical limits. TSOs should refine their congestion management practices to distinguish between voluntary bidding suppression and true capacity bottlenecks. They should also integrate flexible demand agents into congestion relief strategies and ensure they are recognised as active market participants. Enhanced transparency of zonal prices and dispatch signals would further help OWFs be more efficient within CfD regimes.

OWF Developers:

The findings reveal the need for contract-aware dispatch strategies. Under average-based references, OWFs can increase profitability by slightly exceeding the benchmark without overexposing themselves to heavy clawbacks. Developers located at constrained or disadvantaged nodes should advocate for location-adjusted references or strike prices to ensure a level playing field. Moreover, collaborative bidding strategies across OWFs within the same OBZ could mitigate unnecessary curtailment and promote more equitable revenue outcomes.

Regulators and Energy Authorities:

The evidence calls for a re-evaluation of average-referenced CfDs in systems with significant locational or technological heterogeneity. Uniform benchmarks can unintentionally penalise efficient generators and suppress flexibility. Regulators should consider dynamic, location-aware reference mechanisms and run scenario-based simulations before implementing large-scale CfD rollouts. This would help predict not just the financial effects but the systemic operational consequences of these instruments. Moreover, regulators must ensure that clawback structures encourage fair competition without suppressing output from capable OWFs. Additionally, certain turbine technology benefits under the average reference-based CfD policies.

Flexible Demand Providers

The results underline the value of co-locating assets like offshore electrolysers within OBZs. These technologies not only reduce curtailment but can help shape price signals and improve grid efficiency. Their ability to absorb fluctuating wind generation makes them ideal partners for OWFs, and they should be integrated into CfD design considerations. Where possible, such assets should be granted market access privileges or guaranteed offtake conditions during oversupply, especially in high-renewable regions.

In conclusion, this study shows that CfD policies, while essential for de-risking offshore wind investments, can shape system outcomes as well. If not carefully designed, they risk suppressing efficient generation, misaligning incentives, and introducing dispatch distortions. Therefore, policy design must evolve in tandem with system dynamics and actor behaviour.

7.5 Limitations of the Research

7.5.1 CfD policies

The thesis includes a literature review of prominent CfD policies broadly classified into production-based and non-production-based designs. The production-based CfD designs explored include the conventional two-sided CfD with both hourly and yearly average reference pricing, as well as the cap-and-floor CfD, which introduces upper and lower bounds on revenue. These contracts determine payments based on the actual energy generated and sold by the asset, aligning incentives with real-time market participation and production volumes (D. M. Newbery, 2016) (Riesz, Gilmore, & Hargreaves, 2016).

In contrast, the non-production-based CfDs decouple payments from actual output, instead relying on alternative metrics. The reviewed designs include the capability-based CfD, financial CfD, and yardstick CfD. The capability-based CfD, proposed by Elia, compensates generators based on Available Active Power (AAP), a metric reflecting the asset's potential to generate power given real-time weather conditions and system status, rather than the actual dispatched energy. This approach is intended to mitigate the volume risk inherent in production-based CfDs and avoid dispatch distortions (D. M. Newbery, 2016), (Department for Business, Energy Industrial Strategy, 2021). Similarly, the yardstick CfD, proposed by Newbery, calculates remuneration based on a standardised performance benchmark, thereby aligning incentives across locations and promoting efficient market behaviour without relying on individual output levels (D. M. Newbery, 2016).

However, these two non-production-based CfD designs; capability-based and yardstick CfD, are not implemented in this model. The key reason is the data dependency: both mechanisms require high-resolution, asset-level weather or operational data to estimate AAP or to benchmark performance accurately. The current model relies on gridded weather data at the locational level, which is then extended to represent three wind farms situated in the same region. This approach, while practical for financial CfD modelling, does not provide the granularity required for accurate implementation of potential-based CfDs. Without real-time turbine-level SCADA or AAP data, modelling such mechanisms would involve assumptions, therefore compromising result validity.
Furthermore, many non-production-based CfD designs, including the capability-based and yardstick models, can be seen as extensions or variations of financial CfDs, where the payment formula is adapted to reflect potential output or standardised benchmarks. This conceptual similarity supports the decision to focus the modelling framework exclusively on financial CfDs for this phase of the study. Nonetheless, future work could incorporate these advanced CfD structures to enable a more comprehensive comparative analysis of their impact on wind farm operational strategies and market behaviour.

The strike price plays a crucial role in determining not only the revenue of the wind farm but also the operational behaviour. The strike price in the model is assumed based on the average price and the average power cleared in the OBZ. However, this approach does not accurately reflect how strike prices are determined in practice. While strike prices are awarded through competitive auctions, the bids submitted by wind farm developers are underpinned by detailed internal assessments of the asset. Different factors influence the strike price for an individual wind farm depending on the CAPEX, OPEX, wind resource, risk premium and long-term market forecasts. The determination of the strike price was beyond the scope of the project and can be explored to demonstrate the inclusion of a competitive strike price allocation process and subsequent operational behaviour of the wind farms.

7.5.2 Model limitations

The demand in the model is assumed to be perfectly inelastic in each node. In reality, the demand is never perfectly inelastic and is more of a step function, where a certain amount of price responsiveness is observed. There is a flexible demand agent in the form of a hydrogen electrolyser in the model, which has a Willingness to Pay condition. This works as a binary switch, with the electrolyser functioning until the price threshold is reached. To emulate real-world conditions, elastic demand should be considered, allowing for price responsiveness among demand agents.

The wind data used in this study is sourced from the (?, ?) database, which serves as a global repository for weather information. Based on this data and the power curves of the wind turbines, the expected power output is estimated. To account for real-world inefficiencies, a randomised loss factor between 10% and 30% is applied across each timestep. However, this approach does not accurately reflect actual wind conditions or turbine performance. While it simplifies the modelling process, a more accurate representation would require a detailed analysis of turbine behaviour under varying operational conditions. Additionally, the current dataset does not capture forecast uncertainty. In practice, discrepancies between day-ahead (D-1) and two-day-ahead (D-2) wind forecasts can significantly influence operations. Incorporating such uncertainties into the model would better simulate the decision-making environment of wind farm operators and their influence on market outcomes.

The model considers only the first two phases of the market clearing process: the D-2 base case and the D-1 day-ahead market. The redispatch phase is excluded, as the operational decisions of the wind farms are primarily shaped during the earlier stages. While redispatch affects power flows, it does not alter the initial bidding behaviour or dispatch decisions of the wind farms. Payments to the wind farms can still be finalised after redispatch without influencing their operational strategy. However, incorporating the redispatch phase would allow for a more accurate representation of power flows and revenue allocation for offshore wind farms.

As discussed in Chapter 3, the balancing and intraday markets also influence price formation in the day-ahead market. Certain CfD models can cause the price to rise or fall in specific scenarios, leading to a spillover effect on the day-ahead market. This is driven by the bidding behaviour of wind farms under distortive CfD designs. However, the effects of such distortions cannot be examined within this model, as it is limited to the operational behaviour of offshore wind farms in the day-ahead market. An extended version of the model could be developed to incorporate the interaction between the balancing market and the day-ahead market.

The model only considers positive prices, although there are a few instances of prices dropping close to zero or becoming slightly negative. These occur as a result of the market clearing process assigning non-intuitive prices. In reality, negative prices can happen when there is a large oversupply of electricity in the grid. However, this model does not take into account ramping times or unit commitment constraints of thermal power plants. In the model, power plants can instantly start or stop generation as needed, which is not realistic. In practice, thermal plants require time to ramp up or down, and these constraints can add complexity to system operations. Including such features in the model would allow for a more accurate and realistic analysis.

Strategic bidding behaviour of the wind farms is limited only to the volume bid alterations in the model. The price bids are fixed for each hour at zero and are unchanged. There is a certain cost, however, for the production of wind at each hour, which is neglected in this project. The ability of the wind farms to bid strategically in response to the expected prices is removed. They are not able to manipulate their bids to exploit the system, a behaviour observed with production-based CfDs in real-world power markets (Kitzing et al., 2024a). Such strategic bidding can reduce market efficiency and lead to artificially inflated or suppressed prices, ultimately moving the outcome away from the socially optimal solution.

The purpose of the model is to combine the flow-based market coupling (FBMC) clearing process with the operational decisions made by wind farms under different CfD policy designs. To do this, a representative grid model is used, based on the work of (Schönheit et al., 2021) and (Kenis et al., 2023). The model includes three onshore bidding zones and one offshore bidding zone (OBZ), which are interconnected through HVDC links. Although the grid is a simplified version of an actual power system, it still offers meaningful insights into power flows resulting from the market clearing process. The interactions between the three onshore bidding zones and the OBZ play a direct role in shaping the price formation within the OBZ.

In a real system, market dynamics are more complex and involve interactions across a greater number of zones, including those not directly connected to the OBZ. However, limiting the model to just three onshore zones allows for clearer observation of patterns and behaviours within the OBZ, making it easier to draw specific conclusions. A more detailed grid model would capture price formation more accurately, but could make it harder to isolate the effects of specific variables.
This model also assumes a future energy landscape with a high share of renewables, particularly offshore wind. This results in more frequent occurrences of price and volume risks, which helps explore the relevance and necessity of CfD policies under such conditions. Using a current generation profile instead would result in market prices similar to those seen in recent years.

8 | Conclusion

This chapter provides the conclusion to the research questions asked in the beginning of the thesis. Answers to the main research questions and the subquestions are provided through the work done in the thesis in this chapter.

Conclusion

The main objective of the thesis was to analyse how different CfD designs can mitigate price and volume risks for offshore wind farms in Offshore Bidding Zones (OBZs) and how this affects long-term investment and technology choice. Through modelling, a range of CfD types under realistic grid scenarios are studied to provide insights into the tradeoffs between different support mechanisms. Flow-based market coupling with a revenue optimisation model for OWFs in the OBZ is made for studying the operation behaviour of wind farms under such schemes.
Therefore, to get an understanding of the aforementioned behaviour, four research questions are framed and answered in the thesis.

SQ1: Types of CfDs and Relevance to Offshore Markets

What are the different types of CfDs being studied and their relevance in the context of an offshore market?

To answer the first question, extensive literature on the topic has been reviewed. The literature suggests that CfDs can broadly be classified into two categories, namely production-based and non-production-based CfDs. The production-based CfDs work on a strike price, which is determined by a competitive bidding process. The wind farms' revenue in this type of CfD depends on the amount of energy dispatched. Two-sided CfDs, with hourly and yearly reference prices, have been considered. Additionally, cap and floor CfD has also been explored.

Under non-production-based CfDs, more advanced CfD types that decouple payments from the volume dispatched are explored. Financial CfDs, Capability-based CfDs and yardstick CfDs are explored in detail. These CfD designs help to mitigate the risks faced by the OWFs in an OBZ to varying degrees.

SQ2: Risk Challenges and Their Quantification

What are some of the challenges faced by the existing CfD schemes and how can they be quantified effectively?

Initially, the risks faced by the OWFs in an OBZ environment are described qualitatively. The risks faced by the OWFs are categorised into price and volume risks. Under price risks, there is are flat price risks, which means that the price in the OBZ is volatile. Non-intuitive price risk, where the price is out of bounds compared to the onshore zone prices. Price collapse risk, where the lack of export capacity from the OBZ leads to prices collapsing.

In the volume risks, there are two important categories: capacity calculation and capacity allocation risk. Capacity calculation is when the transmission capacity onshore is restricted. The capacity allocation risk is when the transmission capacity is not allocated to the OWF. These are a consequence of the market clearing as per the FBMC process.

To address these risks, production-based CfDs are first deployed. However, they address the price risks through a fixed strike price that provides a high revenue when high volumes of wind are cleared. This, however, exposed the wind farms to volume risks that need to be addressed.

Non-production based CfDs are then analysed as they decouple volume from the revenues received. Specifically, financial CfDs are studied in this thesis. The modelling shows that non-intuitive prices occur for up to 219 hours per year under production-based CfDs and are reduced to 161 hours with financial CfDs. Similarly, the price variance $(e\,/MWh)^2$ decreased from 3.18 to 2.54 using a volume-independent support scheme.

SQ3: Operational Inefficiencies Under CfDs

What are some of the operational inefficiencies triggered by the implementation of the aforementioned CfDs in an offshore environment, and how can they be quantified?

The financial CfDs are a fixed hourly price and the subtraction of clawback from the generator to the government, which hinges on the reference. The selection of this reference is an important parameter in the financial CfD process. This mechanism of revenue maximisation introduces strategies by the OWF that involve strategic bidding. While this solves the price and volume risks, there are certain operational inefficiencies triggered by this. It leads to dispatch distortions, which can harm the system efficiency. OWFs self-curtail wind energy in 69.6 % of the time to the mechanism triggered by the CfD. This process stabilises prices, however, the dispatch inefficiencies are present.

SQ4: Impact on Technology Choice

How does the implementation of a particular CfD measure influence a certain technology choice?

It is observed in the model that certain wind farms in the grid consistently earn higher revenues across different policy choices. The turbines, having a locational benefit and a technological benefit, have an advantage over others. The effect of this is reduced in financial CfDs where the wind farms are forced to bid in a coordinated manner, but it not mitigated completely. The choice of reference is also influenced by technological heterogeneity among wind farms. In average-based reference systems, turbines that perform well during high-value periods benefit disproportionately by facing minimal clawbacks. It faces the least effects of a clawback. In contrast, lower-performing turbines, or those generating power during less valuable hours, incur larger clawbacks and are penalised. A similar distortion arises when wind profiles are misaligned across turbines, making the timing of generation a critical factor in determining clawback exposure. These efficiency issues, though significant, are not yet thoroughly addressed in existing literature.

Technology selection is clearly influenced by CfD design. In Scenario 3, wind turbines with superior performance consistently outperformed others under all CfD schemes. Under a low strike price, revenues ranged from 0.95 million € to 1.61 million €; at higher strike prices, the disparity persisted (7.14M€ vs 7.81M€). These differences arose because high-performing turbines benefited disproportionately from average-based reference pricing. They faced fewer clawbacks, while lower-performing turbines paid more. Turbines with generation aligned to high-value periods performed best under financial CfDs. Thus, even when CfDs remove volume risk, they can still biased investment decisions towards specific technologies and locations.

Main Research Question

How can Contracts for Difference (CfD) schemes be designed and implemented in offshore bidding zones to incentivise investment in offshore wind farms, and how do they influence operational behaviour and technology preferences?

The subquestions help in answering the main research question. Out of all the CfD models that have been studied, financial CfDs solve most of the price and volume risks. However, a deeper look reveals that they trigger certain unwanted system inefficiencies. These have been quantified in the thesis. To solve the inefficiencies it is recommended that greater care is taken in designing the clawback mechanism for the OWFs. It is observed that the referencing method in scenario 1 saw an equal return of revenues to all the wind farms under a financial CfD. This can be extended to say that grouping similar technology choices, within a similar geographical location, to avoid large deviations in the wind profile, can lead to an equitable outcome. The technology choice for the reference is also a driving factor. Beating the reference by a superior technology can earn larger revenues and introduce a basis risk.
In Scenario 5, it was observed that introducing a flexible demand agent, such as an offshore electrolyser, reduced some of the risks. The capacity allocation risks are slashed by half as the power not cleared by the FBMC process can be diverted to the offshore electrolyser.
In conclusion, greater care has to be taken in designing a CfD system. Having smaller and regions under contract can help reduce the basis risk. To incentivise investment in offshore wind, extensive research, including quantitative modelling, is essential for policymakers before designing a CfD contract.

Limitations and Outlook on future work

While the model captures core dynamics of price and volume risk under different CfD schemes, it does not include financial modelling based on the operation costs of a wind farm, uncertainty in market behaviour, or the balancing and intraday markets. These areas offer valuable directions for future work. Additionally, policy-makers should explore combining CfDs with location-specific reference settings and demand-side flexibility mechanisms like offshore electrolysers to support efficient offshore wind integration.

Combining or using a variation of other policies, such as Financial Transmission Rights (FTRs) with CfDs is a promising avenue for future research. While CfDs ensure stable revenues by addressing price volatility, they remain exposed to large-scale congestion. FTRs can complement CfDs by providing the congestion costs to the CfDs (Elia Group, 2024). They can work in tandem to effectively hedge offshore wind from price and basis risks.

In this model, it is observed that there is strategic bidding to restrict the amount of clawback. This is in part due to the amount of wind being curtailed due to volume risks. Introducing FTRs into such a setting could significantly alter these dynamics, providing compensation for congestion-related price spreads and reducing the incentive to game the reference mechanism. Future work can incorporate FTRs in the same model to explore the interplay of the two policies and study the influence of the pairing on the bidding behaviour, dispatch efficiency and investment potential.

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A | Appendix

Table A.1: Summary of Results under Aligned Wind and Same Turbine Technology, No Offshore Electrolyser

Category	Metric	2-Sided CfD	Ref = Node Avg	Ref = Node 98	Only Node 98 CfD	No CfD on Node 98	No CfD on Node 103
Price risks	Mean price (€/MWh)	5.76	6.61	6.61	6.61	6.61	6.54
	Std Dev	14.51	14.39	14.39	14.39	14.39	14.45
	Variance	2.52	2.18	2.18	2.18	2.18	2.21
	Low price hours (h)	567	643	643	643	643	592
	Medium price hours (h)	4	14	14	14	14	4
	High price hours (h)	0	0	0	0	0	0
	Price delta (bids) (h)	0	75	75	75	75	68
	Non-intuitive price (h)	173	87	87	87	87	148
Volume risks	Congested HVDC (h)	625	551	551	551	551	557
	Capacity calculation (h)	394	0	0	0	0	21
	Capacity allocation (h)	543	0	0	0	0	87
General characteristics	Total wind gen (GWh)	599.70	237.19	237.19	237.19	237.19	475.35
	Export @ 0 price (GWh)	511.20	62.17	62.17	62.17	62.17	273.39
	Revenue Farm 1 (€M)	0.50	2.50	1.43	5.42	1.28	2.42
	Revenue Farm 2 (€M)	1.10	2.50	1.43	2.56	2.50	2.42
	Revenue Farm 3 (€M)	3.20	2.50	1.43	2.56	2.50	1.70
	Mean Rev Farm 1 (€)	673.79	3354.86	1920.00	3642.41	1722.41	3252.37
	Mean Rev Farm 2 (€)	1473.18	3354.86	1920.00	1722.41	3354.86	3252.37
	Mean Rev Farm 3 (€)	4301.37	3354.86	1920.00	1722.41	3354.86	2278.33

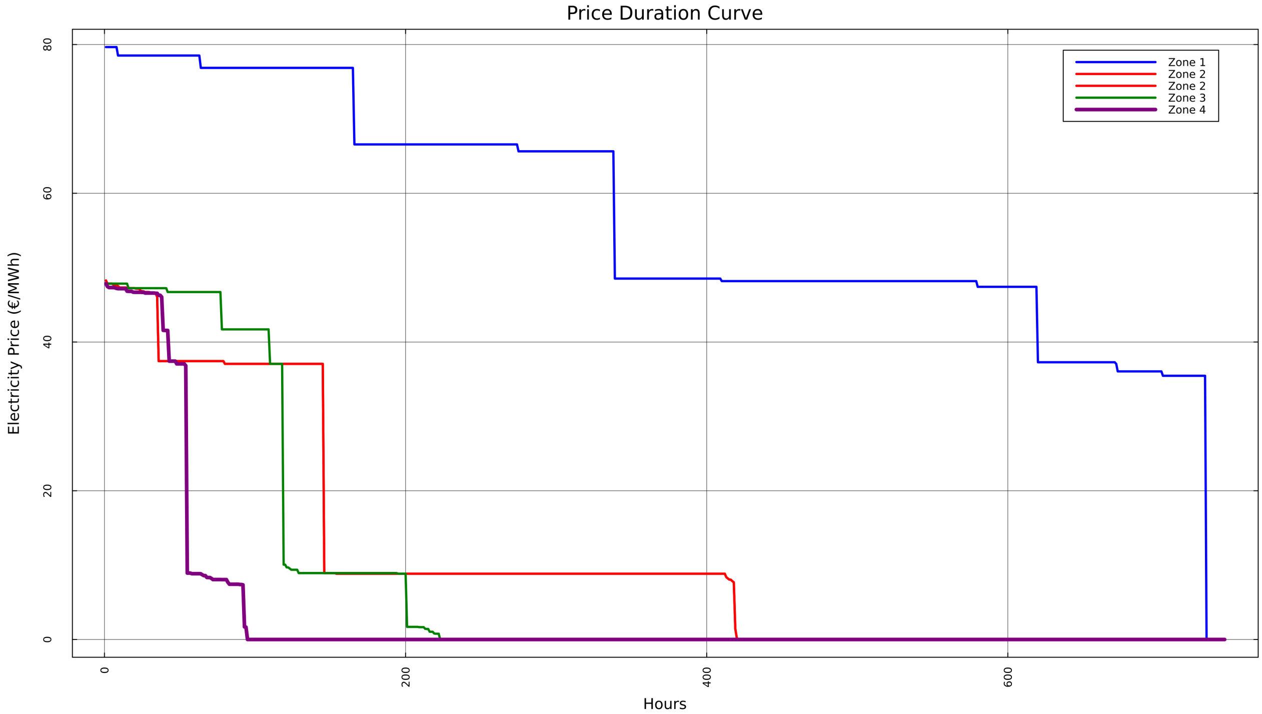

Figure A.1: Price duration curve for Scenario 2

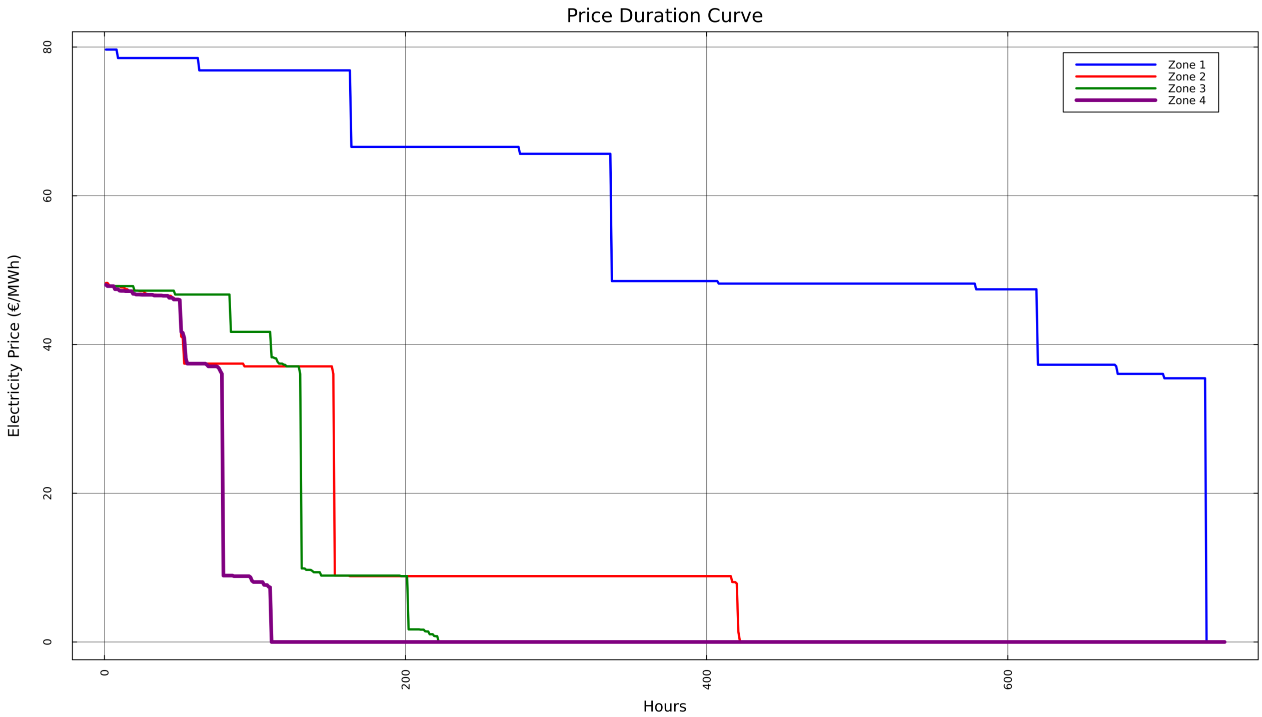

Figure A.2: Price duration curve for Scenario 3

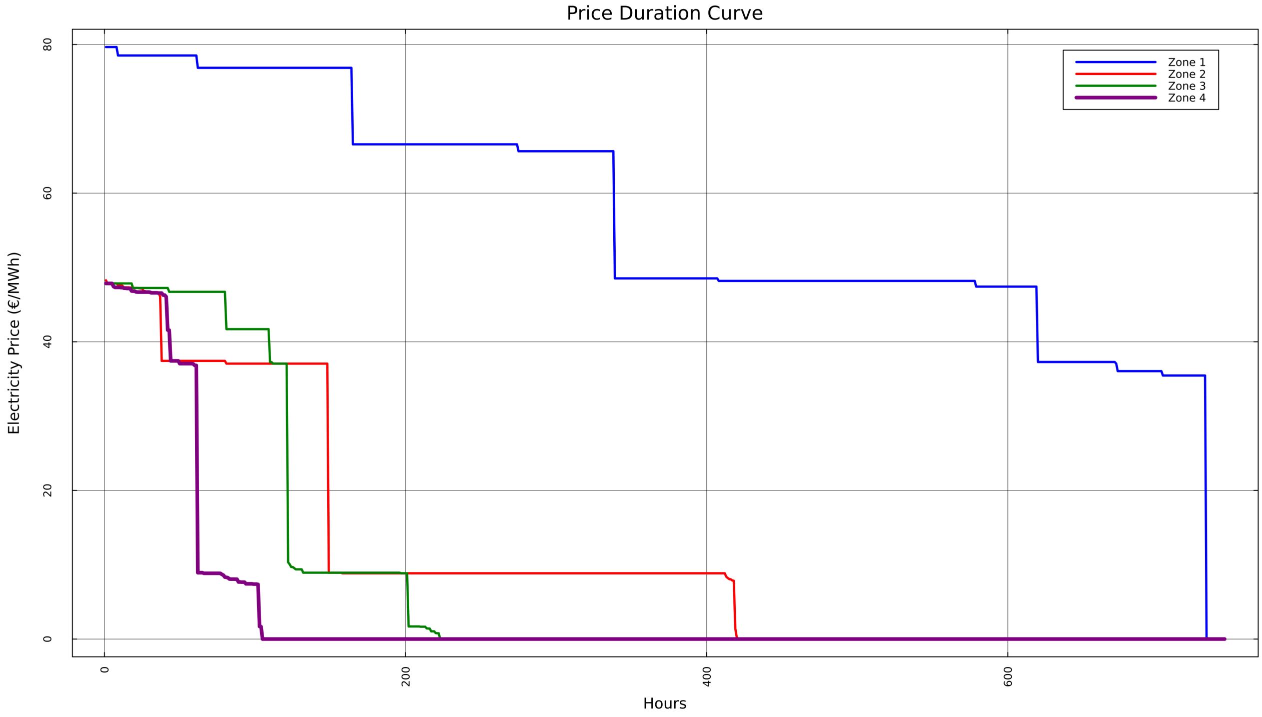

Figure A.3: Price duration curve for Scenario 4

Scenario 2

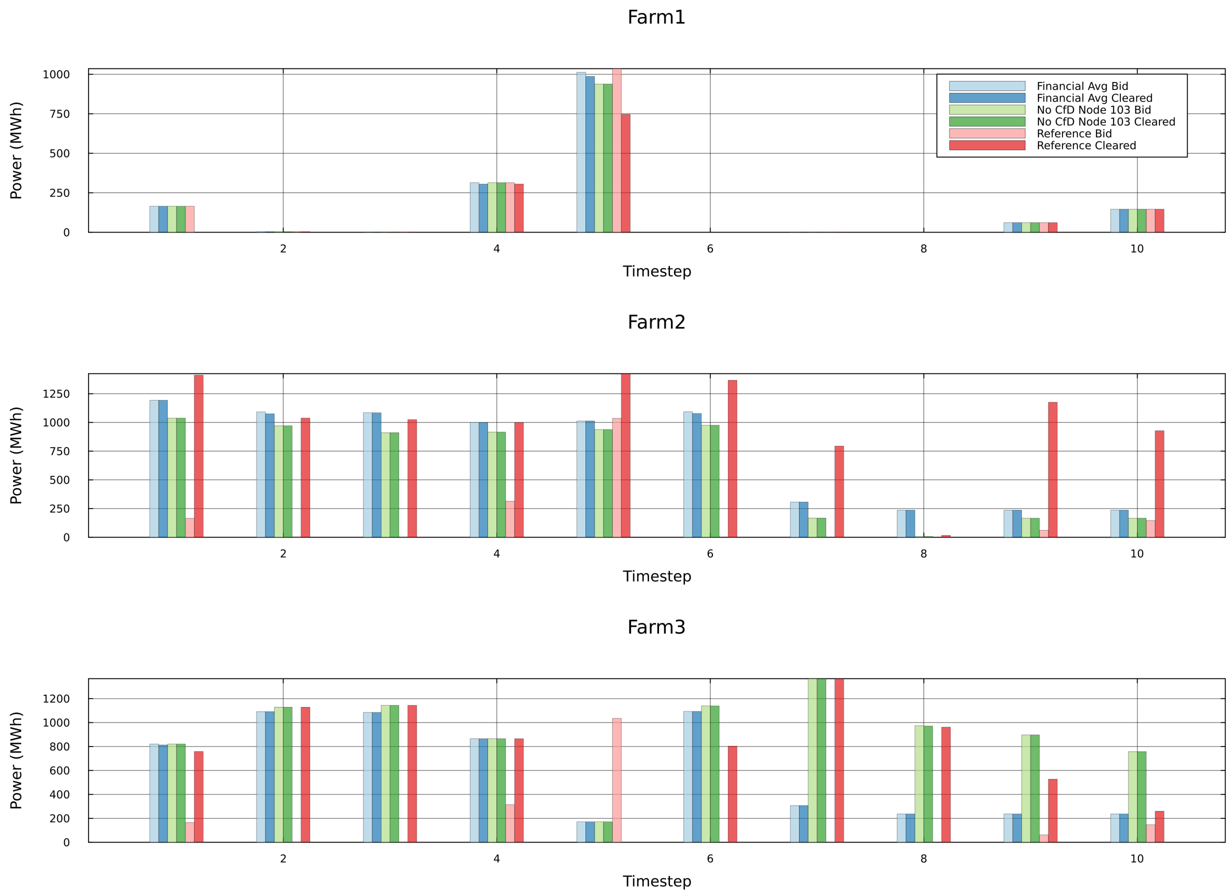

Figure A.4: Bid and cleared volumes for three offshore wind farms across 10 time steps under different CfD policies in Scenario 2