Islands of Opportunity: Unlocking Value in Offshore LNG and Wind Integration

Techno-Economic analysis of enhanced fuctionalities of Princess Elisabeth Island

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Preface

This thesis represents a key academic milestone in completing the Master's programme in Civil Engineering at Delft University of Technology. It has also laid the foundation for the next step in my academic journey, as I prepare to pursue further studies in the field of finance.

The research was carried out in collaboration with Marine & Transport Business Solutions (MTBS), where I had the opportunity to work on a complex real-world challenge at the intersection of offshore infrastructure and economic strategy. I would like to express my gratitude to Professor Mark van Koningsveld for his academic supervision, insightful feedback, and continuous support throughout this project. I am also thankful to Dr. George Lavidas for his technical guidance and critical perspective.

In addition, I extend my appreciation to Dirk van Niekerk and the entire team at MTBS for their mentorship, professional input, and collaborative spirit. Their contributions played an essential role in connecting the academic framework of this thesis to industry relevance and practical application.

S.P.H. Jönsson
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Executive Summary

The global energy landscape is undergoing a significant transformation, marked by the increasing fragility of conventional energy systems and a decisive shift towards electrification to meet climate objectives. This transition elevates energy security and resilience to core priorities for governments and industries. Offshore artificial energy islands are emerging as pivotal strategic infrastructures, particularly in regions like the North Sea, designed to expand renewable energy capacity, alleviate grid congestion, and facilitate power exchange, thereby supporting overarching climate and energy security goals. This thesis investigates how integrating multiple functionalities, specifically energy generation and port logistics, within a single offshore island could enhance financial feasibility. The central research problem addresses how to assess the techno-economic viability of such multi-functional offshore islands, with the Princess Elisabeth Island (PEI) in the Belgian North Sea serving as a representative case study. Current assessment methodologies often fall short in comprehensively evaluating the intertwined financial and operational aspects of combining distinct energy and port functionalities on a unified offshore platform, creating a notable research gap. The primary objective of this research is, therefore, to develop and apply a standardized, transparent Techno-Economic Analysis (TEA) framework tailored for these complex, integrated systems.

The methodological approach is rooted in a TEA framework, systematically applied to the PEI case. This involves a physical breakdown of systems, detailed financial analysis including CAPEX, OPEX, revenue projections, and cash flow modeling, and performance analysis using key metrics such as Levelized Cost of Energy (LCOE), Net Present Value (NPV), and payback periods. The PEI project, planned for 3.5 GW of offshore wind connected via an artificial island housing AC and HVDC substations, formed the initial focus. The base case analysis for PEI as a standalone wind energy hub revealed significant financial challenges: a median LCOE of 224 €/MWh, substantially exceeding recent offshore wind strike prices, and a consistently negative NPV. This financial vulnerability is largely attributed to the dramatic increase in transmission infrastructure costs, which now account for nearly 50% of the total project CAPEX, a sharp rise from approximately 18% in 2020. Sensitivity analyses indicated that the LCOE is highly susceptible to project delays, ranging from 200 to 260 €/MWh, and noted a cooling investor appetite in the European offshore wind sector. Enhanced base case considerations for the wind system showed that an AC-only configuration could reduce the LCOE to 182 €/MWh, while incorporating HVDC as an interconnector, despite potential arbitrage revenues, increased the LCOE to 237 €/MWh, illustrating a trade-off between strategic energy security benefits and immediate financial viability.

To explore multi-functionality, potential port and logistics functions of regional significance to the nearby Port of Bruges were identified. Multi-Criteria Decision Analysis (MCDA) determined an LNG terminal as the most promising candidate for integration onto PEI, with Carbon Capture and Storage (CCS) infrastructure being a secondary, though not further investigated, option. Benchmark base cases were then established for this selected port functionality. An onshore LNG terminal, modeled with a 6.6 mtpa capacity similar to the existing Fluxys terminal at the Port of Bruges, demonstrated a 16-year payback period. In contrast, a standalone offshore LNG terminal on PEI, without any synergies, showed a significantly longer payback period of 27 years, underscoring the inherently higher costs and complexities associated with offshore construction. Uncertainty modeling across various revenue scenarios (e.g., stable growth, geopolitical shocks) confirmed the financial robustness of the onshore terminal, while the offshore counterpart exhibited greater sensitivity, particularly to scenarios involving an accelerated green transition.

The subsequent phase involved designing the multi-functional island, integrating the LNG terminal with the offshore wind energy infrastructure. This integration identified several potential synergies: a more efficient island layout due to an improved area-to-perimeter ratio reducing caisson requirements, and a slight reduction in the AC export cable capacity as the LNG terminal consumes a portion of the generated energy directly on the island. Shared port facilities, such as quays and breakwaters, were also envisioned to reduce overall capital expenditure compared to two separate offshore installations.

Evaluating this combined multi-functional system, the LCOE for the offshore wind component saw a modest 5% reduction, from 224 €/MWh to 214 €/MWh. While an improvement, this LCOE remains uncompetitive, primarily because the dominant cost factor, transmission infrastructure, experiences only minimal reductions from the identified synergies. The payback period for the offshore LNG terminal within the multi-functional system improved to 21 years from the standalone offshore 27 years. However, this is still considerably longer than the 16-year payback for the onshore LNG terminal, suggesting that the direct financial incentives for port stakeholders to participate in such an offshore venture might be limited if based solely on these synergies. Copula-based uncertainty analysis of the combined system, modeling the joint dependencies between gas and electricity prices, indicated that the LNG terminal maintained stable financial performance with less sensitivity to gas price fluctuations, whereas the offshore wind system remained highly sensitive to electricity price volatility. Conditional price modeling showed that conditioning gas prices on electricity forecasts worsened the LNG terminal's performance, while conditioning electricity prices on gas scenarios improved the wind system's outlook.

The investigation confirms that the high LCOE for the PEI offshore wind project is primarily driven by escalated transmission costs, especially for HVDC systems over relatively short distances, and prevailing market conditions, rather than the cost of wind generation technology itself. An AC-only transmission system presents a more cost-effective solution for PEI. While interconnectors offer strategic energy security benefits, they tend to increase the LCOE in the short term. Onshore LNG terminals remain financially superior to their standalone offshore counterparts due to lower CAPEX and operational complexities. The multi-functional island configuration does yield financial improvements for both the energy and port components when compared to their standalone offshore developments, primarily through optimized island construction and shared infrastructure. However, these synergies are not substantial enough to make the offshore wind component competitive with current market strike prices or the offshore LNG terminal more attractive than an onshore alternative from a purely financial standpoint. A critical consideration is the increased systemic risk; concentrating vital energy infrastructure on a single platform amplifies the potential impact of major failures.

A major limitation is that the analysis did not consider second-order benefits for the PoB. Specifically, relocating the LNG terminal offshore could free up valuable port land that might otherwise be used for higher value-generating functions, such as container terminal expansion—potentially offering substantial strategic and economic advantages that were not captured in the current evaluation.

Limitations of this research include the flow of mass model encountering difficulties with non-standard or bidirectional flows inherent in systems with interconnectors or dynamic storage. The absence of a universally adopted industry standard for supply chain breakdown necessitated a custom cost coding system. Furthermore, the inherent complexity of the OpenTESim software might pose usability challenges for broader industry adoption without programming expertise. Energy production calculations were conservative and did not deeply model complex phenomena like turbine wake effects. Access to granular cost data for specific advanced components (like HVDC internals or current LNG equipment) was limited, and long-term market and revenue scenarios remain inherently speculative.

In conclusion, this thesis demonstrates that the techno-economic feasibility of multi-functional offshore islands integrating energy and port functionalities can be systematically assessed using an adapted TEA framework. This approach, which incorporates methodologies like MCDA for function selection and detailed modeling of operational and financial synergies, provides a replicable and transparent tool for evaluating such complex projects. While the multi-functional design applied to the Princess Elisabeth Island case did unlock certain financial benefits and efficiencies through shared infrastructure and optimized layouts, these were insufficient to overcome the high prevailing costs of offshore transmission infrastructure for the wind component or make the offshore LNG terminal more financially attractive than its onshore counterpart. The study underscores that while multi-functionality can improve the business case compared to isolated offshore developments, truly transformative financial gains may require the integration of functionalities with very high on-island energy consumption, such as CO2 liquefaction, to achieve more substantial reductions in export infrastructure costs. Ultimately, offshore artificial islands should be viewed as flexible, long-term assets whose full value can only be unlocked through strategic, multi-functional design and integrated techno-economic assessment.

Contents

Nomenclature

Table 1: List of Abbreviations

Abbreviation	Definition
AC	Alternating Current
BESS	Battery Energy Storage System
BSC	Balanced Score Card
CAPEX	Capital Expenditures
CCS	Carbon Capture Storage
CDF	Cumulative Density Function
CO2	Carbon Dioxide
COR	Code of Resources
DC	Direct Current
DG	Directed Graph
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EBT	Earnings Before Tax
ESDL	Energy System Description Language
FCF	Free Cash Flow
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LCOX	Levelized Cost of Commodity X
LNG	Liquified Natural Gas
MCDA	Multi Criteria Decision Analysis
MCA	Multi Criteria Analysis
MCDM	Multi Criteria Decision Making
MILP	Mixed Integer Linear Programming
MOG2	Modular Offshore Grid 2
NREL	National Renewable Energy Laboratory
NPV	Net Present Value
OEH	Offshore Energy Hub
OPEX	Operational Expenditures
PBS	Physical Breakdown Structure
PEI	Princess Elisabeth Island
PEZ	Princess Elisabeth Zone
PFD	Process Flow Diagram
PoB	Port of Bruges
RoRo	Roll-On Roll-Off
SAB	Standard Activity Breakdown
TEA	Techno-Economic Analysis
WACC	Weighted Average Cost of Capital

1 Introduction

1.1. Research Context

The last decade has revealed the vulnerabilities of modern energy systems. The COVID-19 pandemic disrupted supply chains, the Russian invasion of Ukraine triggered a continent-wide energy crisis, and the Iberian near-blackout underscored how fragile grid stability can be under stress (Kuzior et al., 2025, LaBelle, 2024). These diverse events share a common lesson: energy is no longer an unquestioned constant. In the emerging Age of Electricity, secure, reliable, and resilient access to energy has become a central challenge for governments, industries, and citizens alike (Gritz and Wolff, 2024).

This evolving energy landscape is marked by a historic pivot away from fossil fuels toward renewable electricity. As the share of renewables grows, so too does the complexity of ensuring a stable and affordable energy supply (Hartvig et al., 2024). Energy security is no longer just about diversifying fossil fuel imports or building strategic reserves; it now encompasses the robustness of transmission networks, the integration of variable renewables, and the ability to manage cross-border electricity flows in real time (Khan et al., 2024, Tugcu and Menegaki, 2024).

Against this backdrop, offshore artificial energy islands have emerged as a new class of strategic infrastructure. Positioned in the North Sea and other maritime zones, these engineered platforms offer a bold response to the dual challenges of decarbonization and resilience. They expand the available area for offshore renewable generation, relieve onshore grid congestion, and facilitate cross-border power exchange. Plans for these islands, once visionary, are now gaining urgency in Europe's push for energy independence and climate neutrality (Jansen et al., 2022, Denny and Keane, 2013).

1.1.1. Energy Security in the Age of Electrification

Electrification is reshaping the foundations of energy systems worldwide. Driven by climate policy and industrial modernization, sectors such as transport, heating, and manufacturing are shifting from fossil fuels to electric alternatives. Electricity is no longer just one energy vector among many, it is becoming the backbone of entire economies (Gomila et al., 2025, Kapica et al., 2024).

Yet, this shift introduces profound challenges. Renewable energy sources like wind and solar are intermittent, making electricity generation less predictable and more spatially distributed. Traditional energy systems, designed for centralized and controllable power plants, must now adapt to fluctuating supply patterns. In countries where renewables already provide over 40% of electricity, the need for flexible and resilient grid infrastructure has become critical (Pollitt et al., 2024, Do et al., 2024, Adnan et al., 2024).

Meeting this need requires enormous investment. The International Energy Agency (IEA) estimates that over 80 million kilometers of power lines must be built or upgraded globally by 2040 (López et al., 2024). Europe alone faces more than €500 billion in transmission costs by 2030. However, grid expansion is often delayed by permitting hurdles, spatial limitations, and high capital intensity (Herranz-Surralles, 2024).

To bridge these gaps, a range of flexibility solutions is being deployed. Battery Energy Storage Systems (BESS) help stabilize the grid by mitigating short-term imbalances and reducing renewable curtailment (Grisales-Noreña et al., 2024, Mohamed et al., 2024). Hydrogen, produced from surplus electricity, offers long-term energy storage and sector integration (Gatto et al., 2024). Still, both technologies face technical and financial barriers, including safety concerns, degradation, and the need for large-scale infrastructure (Boretti and Pollet, 2024).

A growing symptom of the mismatch between generation and demand is the frequent occurrence of negative electricity prices, periods when wholesale power prices fall below zero . These events are especially common in markets with high renewable penetration and limited transmission or storage capacity (Shimomura et al., 2024). Negative prices reflect a system where surplus generation cannot be absorbed, leading to curtailment of clean energy and undermining investment signals. While these price patterns are a natural consequence of variable supply, they erode the cost-effectiveness of the energy system by reducing the revenues of renewable generators and increasing the need for subsidies or market reform (Halbrügge et al., 2024, Entezari and Fuinhas, 2024).

These challenges are reshaping the definition of energy security, from a focus on supply sufficiency to one of systemic robustness. Security now depends on integrated solutions that combine generation, transmission, storage, and cross-border coordination (El-Emam et al., 2024, Aziz et al., 2024).

1.1.2. The Role of Offshore Energy Islands in Energy Security

Offshore energy islands directly respond to this new understanding of energy security. By serving as energy hubs, they offer a platform for integrating offshore wind generation, HVDC substations, and international grid connections, all in one centralized location (Bueger and Edmunds, 2024).

Their value lies in their ability to support meshed offshore grids, enabling electricity from remote wind farms to flow flexibly between national systems. This improves system balancing, reduces congestion onshore, and enhances resilience during regional disruptions. In doing so, energy islands transform offshore space into an extension of the continental electricity grid (H. Zhang et al., 2022b).

Moreover, these islands can host storage and conversion technologies such as BESS and Power-to-X (e.g., hydrogen production), providing both short-term and seasonal balancing options. Co-locating such systems minimizes infrastructure redundancy and offshore footprint, while enhancing the efficiency and stability of the overall system (Lin et al., 2016, McKenna et al., 2021)).

Designed for a multi-decade lifespan, energy islands allow for a phased rollout of technologies. Initial configurations may focus on transmission and grid integration, with additional capabilities such as CO_2 transport or hydrogen exports added as markets mature and policies evolve. This modularity supports long-term planning and adaptability (Lüth et al., 2024).

Importantly, energy islands also foster transnational cooperation. Through joint investment and shared infrastructure, they offer a concrete mechanism for deepening European energy integration, reducing geopolitical exposure, and aligning national interests with regional energy security goals (Rettig et al., 2023, Groppi et al., 2021).

In this context, the research into offshore energy islands is not merely timely, it is vital. These infrastructures sit at the intersection of technical innovation, policy ambition, and geopolitical necessity, making them a cornerstone of the secure, decarbonized energy systems of tomorrow (Groppi et al., 2021).

1.1.3. Energy Island Concepts

Energy islands are emerging as a key solution to connect large-scale offshore wind to the grid, but they vary significantly in form and function, from artificial land reclamations to floating platforms. While most early-stage concepts focus on electricity transmission, others integrate energy storage, power-to-X facilities, or port infrastructure (Tosatto et al., 2022, DNV, 2024b). Over time, these hubs could evolve into multi-functional energy nodes supporting industrial decarbonization, maritime transport, and cross-border interconnectivity (Tsagkari and Roca Jusmet, 2020, TNO, 2024).

Among the most notable projects is Denmark's planned artificial North Sea energy island, intended to connect up to 10 GW of offshore wind. With projected costs as high as €30 billion, the project illustrates both the promise and the immense financial burden of such developments (International Chamber of Shipping, 2024, *Denmark as the Energy Island Pioneer*, 2023). Similarly, Bornholm (Denmark) and Helgoland (Germany) will serve as natural-island-based hubs, with Bornholm linking 3–5 GW of wind to neighboring countries and Helgoland aiming for 10 GW integration by 2035. The Netherlands is also exploring hybrid island-platform solutions in the North of the Wadden Sea, targeting 4 GW by 2030 and more than 10 GW by 2040 (Papazu, 2017, Kristiansen et al., 2018, DutchNews, 2024).

However, the high CAPEX, often exceeding €10 billion, raises economic concerns. Without integrating storage or conversion functionalities, the LCOE increases, undermining the financial viability of such projects (Quirk et al., 2021). The Danish postponement of its North Sea Energy Island project due to risk concerns highlights the challenges (International Chamber of Shipping, 2024). The increasing frequency of negative electricity prices also underscores the need for energy islands to incorporate storage and conversion functions to mitigate financial risks (Kruse-Andersen and and, 2024).

1.1.4. The Case for Multi-functionality

As energy islands grow in scale and strategic importance, interest is increasing in multi-functional configurations that combine transmission with energy conversion (e.g., hydrogen or ammonia), storage, or maritime logistics. These integrated systems could offer ways to better absorb intermittent supply, reduce curtailment, and create diversified revenue streams (Tosatto et al., 2022).

While current developments largely prioritize transmission, especially in early project phases, several concepts under consideration explore phased or immediate integration of additional functionalities. The rationale is that multi-functionality may allow islands to provide greater system flexibility, buffer against volatility, and make more efficient use of limited offshore space (Marczinkowski et al., 2022).

However, the financial viability of such multi-functional configurations remains uncertain. While they may theoretically reduce curtailment and improve asset utilization, they also introduce significant technical complexity and additional capital expenditure. Whether the added functionalities help offset or exacerbate the already extreme CAPEX associated with artificial islands is a key question, which has not yet been studied.

1.1.5. Princess Elisabeth island

Princess Elisabeth Island, located 40 km off the Belgian coast and envisioned as a key offshore hub, is designed to serve as a vital link between the country's second offshore wind zone (Princess Elisabeth) and the onshore high-voltage grid. With a planned area of around 5 hectares above the waterline, the island will play a crucial role in facilitating offshore wind energy operations, but its potential goes beyond just energy production. By incorporating logistics functionalities, such as cargo handling and transshipment service, the island could potentially improve its financial viability and help alleviate growing congestion at the Port of Bruges. This integration could enhance operational efficiency, provide a flexible system to adapt to changing market demands, and create a more resilient and sustainable infrastructure (Elia, 2023, Arcadis, 2023, Hardy et al., 2022).

The island's design features include concrete caissons filled with sand, a small harbor, and a helicopter platform for crew maintenance access. With the construction contract awarded to Belgian companies DEME and Jan De Nul, the project is set to be completed by 2030. It will connect three offshore wind farms and facilitate undersea cable connections to the UK and other North Sea countries (RUMES et al., 2022, Delbeke et al., 2023, Jan De Nul, 2024). However, while the island is critical for Belgium's energy transition, the project has faced significant cost challenges. Initial estimates placed the cost at 2.2 billion euros, but rising expenses largely driven by supply chain pressures, inflation, and increased material prices, could push the final price tag to as much as 7 billion euros. This surge in costs raises concerns about the potential impact on consumers and businesses, with energy tariffs already expected to rise as a result (Van der Straeten, 2022, Goethals et al., 2023, OffshoreWIND.biz, 2025).

To unlock the full potential of offshore islands like Princess Elisabeth, it is essential to establish a standardized framework for evaluating their potential multi-functionality. Such a framework would ensure that various projects are assessed consistently, providing a benchmark for comparing different cases and promoting greater standardization across the industry. By integrating both energy and logistics functionalities, offshore islands could become more financially viable and play a central role in

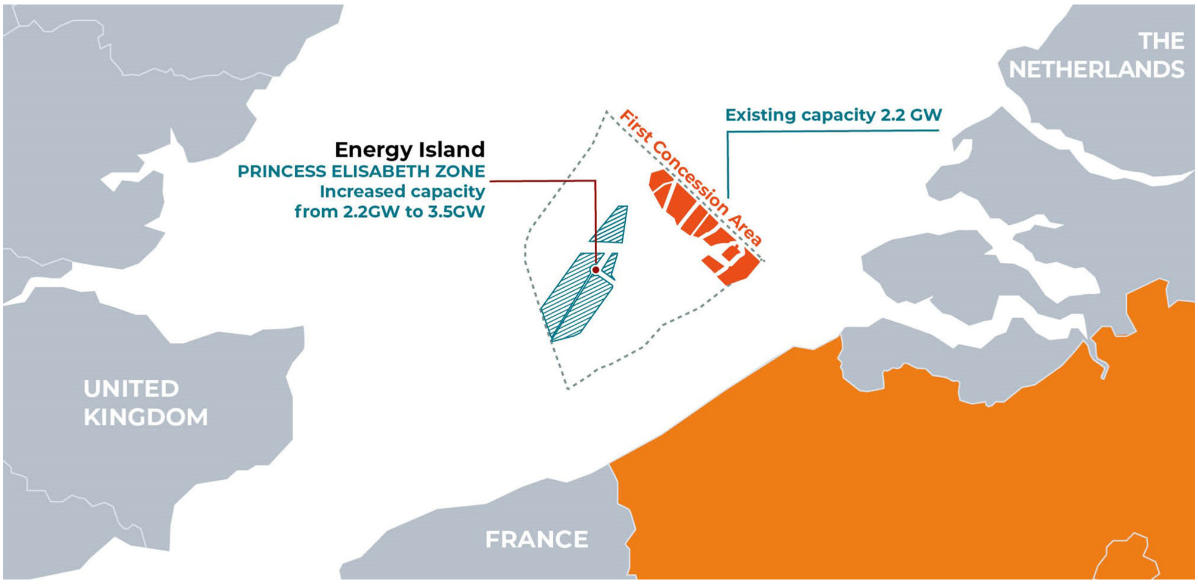


Figure 1.1: Offhsore Energy Zones Belgian North Sea (Elia, 2023).

advancing regional infrastructure, supporting both renewable energy and maritime logistics.

1.1.6. Standardized Method and Industry Standard Elements

Multi-functional offshore islands, which integrate both energy and logistics systems, presents a significant challenge for infrastructure development. With the growing complexity of offshore energy projects, especially those combining energy generation, storage, and port functionalities, a comprehensive system approach is required to ensure the successful design and implementation of these projects. The traditional focus on individual components, whether for energy production, logistics, or infrastructure, often leads to suboptimal solutions when considered in isolation. Developers could tend to prioritize the optimization of specific functions (e.g., wind energy generation or LNG storage) without considering the broader system integration, leading to inefficiencies and missed opportunities for synergy (Ninan et al., 2024, J. Wang et al., 2020).

The challenge lies in assessing the overall feasibility and financial viability of multi-functional offshore islands. For instance, while one component, such as wind turbines or energy storage systems, may be optimized for performance, it might not fit seamlessly into the larger context of the island's multi-faceted role. If an energy island's primary function is to serve as a hub for offshore wind farms, but it is also expected to handle logistics such as cargo and transshipment, the design must incorporate flexibility and adaptability across multiple domains. Without considering the interdependencies and holistic needs of the system, projects may face issues with operational efficiency and economic sustainability (Zaręba, 2014, Bakker, 2024, Van den Haak, 2023).

Large-Scale System Thinking through Standardized Methods

To navigate these complexities, the adoption of a standardized method for assessing multi-functional offshore islands is essential. A transparent and consistent framework would enable stakeholders to evaluate various designs and operational models in a way that aligns with both energy and logistics goals. By standardizing the assessment process, a more integrated and effective approach can be developed, allowing for the seamless integration of multiple functions, such as renewable energy production, storage, and logistics operations, into a single offshore platform (Bakker, 2024, Onat et al., 2017).

Such a framework could be modeled on existing methods, such as the LCOE used in energy systems, which helps compare different energy production concepts (Mattar and Guzmán-Ibarra, 2017). A similar approach could be applied to offshore islands to assess the combined cost-effectiveness of energy generation and logistics functionalities. The creation of a standardized assessment method would allow for more informed decision-making, enabling developers to better understand the trade-offs between different design choices and their impact on the overall system. This approach would also encourage industry-wide collaboration, facilitating the sharing of best practices and lessons learned across projects.

Large-Scale System Thinking through Industry Standards

In addition to a standardized assessment method, implementing industry-standard supply chain elements is essential for the successful deployment of multi-functional offshore islands. Standardization ensures a common language across the various stakeholders involved, allowing for clearer communication and reducing the risk of misunderstandings during techno-economic assessments (Snell, 1997).

By standardizing supply chain elements, the process becomes more transparent and predictable, allowing stakeholders to check the level of detail specified for each element in the project. This provides clarity on what has been defined and ensures that everyone is aligned in terms of expectations and requirements. Moreover, standardization helps reduce uncertainty, streamlines operations, and enhances the ability to adhere to project timelines and budgets (Brkić and Praks, 2020).

Absence of Standardization in Multi-functional Offshore Island Assessments

Currently, there is a lack of standardized methods for comparing multi-functional offshore island concepts, particularly those that integrate both energy and logistics functions. While some studies have attempted to assess offshore energy islands, they often focus on isolated components or lack a consistent approach to comparing various designs. As a result, stakeholders, whether government bodies, developers, or logistics operators, may struggle to evaluate the full potential of these projects and understand the economic and technical implications of different design choices (Landerud and Zöllner, 2022, Østebø et al., 2018) .

By establishing a standardized assessment method for multi-functional offshore islands, it would be possible to generate a clear benchmark for comparing different designs and operational models. This would enable more transparent, consistent, and reliable evaluations, helping to unlock the full potential of these innovative projects. Furthermore, integrating industry-standard supply chain elements into the assessment process would enhance the practicality of these models, ensuring that projects are not only technically feasible but also financially viable.

1.2. Research Problem

Current approaches to designing offshore islands primarily focus on energy generation and storage, often overlooking the potential economic benefits of integrating port functionalities. This lack of multi-functionality might limit the overall financial returns of these projects, ultimately weakening their investment appeal, especially in the context of increasing demands for both energy infrastructure and logistical services.

The core problem addressed by this research is: **How can the techno-economic feasibility of multi-functional offshore islands, integrating energy and port functionalities, be assessed?**

To effectively assess the financial feasibility of these multi-functional offshore islands, a standardized evaluation method is required. This method must enable consistent assessment of both energy and logistical functionalities, incorporating key supply chain elements and offering transparency and comparability across different cases. By doing so, it will provide a clear and robust framework for understanding the potential financial returns of offshore islands that serve both energy and port functions.

1.3. Research Gap

To identify the most suitable way to assess multi-functionality, it is necessary to evaluate existing research methods.

Offshore Energy Islands

Recent methods have been developed to assess the feasibility of offshore energy hubs (OEHs). H. Zhang et al. (2022a) developed an investment planning and operational optimization model for offshore energy systems, concentrating on the integration of OEHs. The model, a mixed-integer linear programming

(MILP) framework, provides a high level of operational detail, including hourly device-level energy consumption at a large scale. This methodology combines investment planning with operational strategies to identify cost-optimal solutions.

Lüth and Keles (2024) developed a multi-criteria assessment framework for OEHs, combining literature-based analysis with a multi-criteria analysis (MCA) approach. The framework evaluates technical, economic, ecological, and societal factors, highlighting the risks and benefits of integrating mature and emerging technologies. Key challenges identified include high capital costs, uncertain payback periods, and the need for a robust regulatory framework. The paper also discusses environmental impacts and the necessity for further research into technology choices, design specifications, and operational modes to guide future implementations.

Although these methods provide useful foundations for assessing OEHs, they do not focus on investment case analysis in a way that fully integrates both offshore energy and logistics supply chains. Additionally, the financial evaluation methods used for the Princess Elisabeth Island or other projects are not publicly available, creating uncertainty about the specific models employed.

Offshore Ports

Research on offshore port systems has primarily utilized MILP models to optimize operations. For example, Kurt et al. (2023) applied MILP to evaluate the operational costs of integrating offshore container ports into global shipping networks. While this research offers valuable modeling insights for offshore port evaluations, it is limited to container handling and does not extend to multi-functional offshore islands or broader supply chain considerations.

Further research by Kurt et al. (2023), though not publicly available, presents a standardized method for cost analysis of offshore ports. However, these studies do not address the integration of offshore ports with energy hubs, leaving gaps in assessing their combined functionalities.

Offshore Energy

Researchers at TU Delft have contributed to the development of standardized methods for offshore energy systems. Van den Haak (2023) and Bakker (2024) focused on offshore hydrogen supply chains, providing insights into the applicability of offshore islands. More importantly, their work established a foundation for standardizing economic evaluations of offshore energy systems by assessing existing methodologies, supply chain analysis, and more efficient ways of evaluating investment cases. These methods are crucial for advancing standardization in the offshore industry and will serve as a primary foundation for this research.

Gap

Although various methods exist for assessing offshore energy systems, ports, and energy hubs, none have been developed to evaluate multi-functional offshore islands that integrate both energy and port functionalities into one system.

Recent research presents a significant advancement in evaluating offshore wind supply chain configurations and energy island feasibility. However, gaps remain in addressing the integration of cross-industry frameworks and international standards. The study emphasizes transparency and the use of open-source techno-economic models, this allows for comparability across regions and projects, leaving less ambiguity in assessing cross-border energy transition initiatives.

Additionally, while Bakker and van den Haak provide a techno-economic evaluation of offshore energy islands, their approach excludes interdependencies between energy and logistics/port hubs. The omission of benefits beyond hydrogen production suggests an incomplete valuation of the energy island's multi-faceted potential. Addressing these gaps through a holistic approach that integrates logistics, maritime needs, and evolving offshore standards will strengthen the study's contributions and relevance to the offshore energy and logistics industries.

The key research challenge lies in developing a systematic method that adapts established techniques from transport and energy hubs to identify and evaluate additional functionalities. These functionalities should complement the energy-focused activities of OEHs while aligning with regional logistical needs. This research aims to develop a standardized method for evaluating multi-functional offshore islands, bridging the gap between offshore energy and port infrastructure assessments.

1.4. Objectives & Scope

1.4.1. Objectives

The primary goal of this research is to develop a standardized method for evaluating and enhancing the multi-functionality of offshore energy artificial islands, improving their economic feasibility. Specifically, this study will:

1. Develop a method for identifying and evaluating potential functionalities: Analyze energy operations, cargo types and logistical operations that could be handled by offshore islands, prioritizing them based on technical and economic viability.
2. Propose and standardize methods for alternative configurations of multi-functional islands: Design and develop configurations that integrate high-potential functionalities identified in the first step. This involves adapting and applying existing methods from energy infrastructure, port logistics, and offshore engineering to create a consistent framework for evaluation and benchmarking. The standardized method will ensure applicability across diverse offshore island projects.
3. Apply the developed methods to the case of Princess Elisabeth Island: Assess whether integrating selected port functionalities, supported by renewable energy production, can improve its financial feasibility in conjunction with the Port of Bruges.

1.4.2. Scope

This study focuses on creating a systematic framework for evaluating multi-functionality of offshore islands, emphasizing their economic and technical feasibility. The research will assess a proactive (incorporating functionalities during initial design) approach to multi-functionality. It excludes detailed engineering design and focuses on high-level techno-economic analysis, offering actionable insights for similar projects.

Through this research, the study aims to contribute to developing integrated offshore hubs that support both energy and logistics operations, driving innovation in offshore infrastructure design and economic strategy.

1.5. Research Questions

The central research question guiding this study is:

How can the techno-economic feasibility of multi-functional offshore islands, integrating energy and port functionalities, be assessed?

To address this question, the following sub-questions are defined:

1. What methods have been used to assess the techno-economic feasibility of offshore islands?

This question seeks to identify existing methodologies in the literature that assess the techno-economic feasibility of offshore islands, particularly those that integrate energy infrastructure and port functions. By reviewing relevant case studies and research, this question aims to highlight the gaps and limitations in current models, especially with regard to multi-functional islands. Additionally, it will explore how these methods can be refined or extended to account for the complexities of combining energy and logistics systems.

2. What industry standards can be used to develop a more transparent evaluation method?

In alignment with the first question, this question is focused on identifying industry standards that could be integrated into the assessment model to ensure transparency and consistency in evaluations. The research has identified that existing techno-economic models could benefit from more automated processes, particularly in the generation of supply chain configurations. Moreover, the development of a detailed cost estimation tool for energy island projects could significantly enhance the robustness and reliability of techno-economic assessments. This question will explore which established standards, both within energy and logistics sectors, can be incorporated to improve the evaluation framework.

3. What are the potential energy operations and port functionalities that offshore islands can accommodate, and how can they be systematically identified and prioritized?

This question seeks to identify the wide range of potential operational functions that multi-functional offshore islands can accommodate, focusing on both energy-related activities (such as offshore wind farm integration, energy storage, and power distribution) and port-related functionalities (such as cargo handling, transshipment services, and logistics). Furthermore, it will address how these functions can be systematically identified, categorized, and prioritized based on factors such as market demand, technical feasibility, and economic impact. The goal is to establish a clear methodology for evaluating which functionalities should be integrated into specific cases, considering their potential impact on the overall feasibility of the project.

4. What alternative configurations of offshore islands can integrate these functionalities, and how can their technical, energy, and financial feasibility be assessed using a standardized method?

This question explores how different configurations of multi-functional offshore islands, integrating both energy and port functionalities, can be modeled and assessed. This method will check whether combining energy and port functionalities on an island yields better returns than considering the two functions separately. The evaluation will consider the technical and financial feasibility of the alternative configurations, and determine whether integrating the functions leads to improved performance or cost-efficiency. This question aims to create a comprehensive evaluation framework for assessing multi-functional offshore islands.

5. How can the proposed method be applied to the case of Princess Elisabeth Island to evaluate its impact on economic and energy feasibility?

This final sub-question involves applying the proposed standardized assessment method to a real-world case: Princess Elisabeth Island. By using this case study, the feasibility of integrating energy and port functionalities on an offshore island will be tested and evaluated. This question aims to demonstrate how the method can be used in practice to assess the potential financial returns and technical performance of such a multi-functional offshore island, taking into account both the energy supply from offshore wind farms and the logistical requirements of port services. The results of this analysis will offer insights into how the method can be applied to other projects, providing a practical example of its value and versatility.

1.6. Thesis Outline

This thesis is structured into seven main chapters, each addressing a critical aspect of the research.

The *Introduction* chapter provides an overview of the research problem, objectives, and scope. It introduces the importance of assessing the financial feasibility of multi-functional offshore islands and outlines the research questions and methodology. The second chapter presents a literature review of existing techno-economic assessment methods used for offshore infrastructure projects. Additionally, it examines relevant industry standards that can be leveraged to develop a more transparent and standardized evaluation method. *Techno-Economic Analysis* forms the third chapter, offering a structured breakdown of the techno-economic analysis model. The fourth chapter, *Method for Evaluation*, introduces the proposed standardized evaluation framework. It details the methodological approach, including key variables, metrics, and models used to assess the technical, financial, and logistical feasibility of offshore islands integrating both energy and port functionalities. *Case Study: Application to Princess Elisabeth Island* is covered in the fifth chapter, where the proposed evaluation method is applied. This chapter describes the data inputs, assumptions, and implementation process, demonstrating how the framework can be utilized to evaluate the feasibility of the project. The sixth chapter, *Results and Discussion*, presents the findings of the analysis. It interprets the outcomes in relation to the research questions, compares different configurations, and discusses the implications of integrating energy and port functionalities on offshore islands. Finally, the *Conclusion and Recommendations* chapter summarizes the key insights from the research, highlights its contributions, and provides recommendations for future studies and practical applications in offshore island development.

2
Literature Review

The purpose of this literature review is to examine existing research on methodologies for assessing and implementing multi-functionality in offshore islands. The review focuses on identifying methodologies for evaluating potential functionalities, determining feasibility, and assessing the added value of multi-functional islands. It further explores whether any methods exist specifically for offshore energy islands and inventories methodologies from related fields to develop a standardized framework for multi-functional offshore islands.

2.1. Feasibility assessment methods within literature

In this section, feasibility assessment studies within academic literature in the offshore industry are analyzed. Common methods within the industry are examined and identified. Techno-economic assessments are a common method for evaluating the feasibility of offshore projects. These assessments consider technical factors like system efficiency, as well as financial factors such as costs, cash flows, and discounting, often referred to as part of financial assessment studies (U.S. Department of Energy, 2022).

2.1.1. Techno-Economic Analysis

Techno-Economic Analysis (TEA) is a method for assessing how system interventions translate into costs, ensuring infrastructure investments are both technically and financially viable. This framework is adaptable to plenty of industries, such as offshore energy.

Existing Framework for Techno-Economic Analysis

TEA typically follows a structured methodology (Van Koningsveld, 2024):

- Physical Breakdown Structure: Process design, process modeling, and component engineering to establish system feasibility.
- Financial Analysis: CAPEX and OPEX estimation, revenue projection, and cash flow analysis to assess investment viability.
- Performance Analysis: Evaluation using key financial metrics such as NPV and IRR.

When explicit market values are unavailable, levelized cost metrics such as LCOE and LCOH provide standardized cost assessments (Thommessen et al., 2021a, Han and Lee, 2014).

While the TEA framework is applicable across industries, its standardization remains a challenge (Martinez and Iglesias, 2024). Further refinement and formalization of TEA methodologies, specifically for multi-functional offshore hubs like the Princess Elisabeth Island is needed. By integrating industry standards and improving financial assessment techniques,the broader adoption of TEA as a standardized evaluation method is supported.

OpenTESim: Open-Source Software for Techno-Economic Simulation

OpenTESim is an open-source software package designed for techno-economic simulations, enabling users to model, analyze, and optimize various infrastructure and energy projects. Built with flexibility and modularity in mind, OpenTESim provides a framework that integrates technical and economic parameters to assess project feasibility under different scenarios (Van Koningsveld, 2024).

A key advantage of OpenTESim is its modular design, allowing users to create and customize simulation components to represent different assets, costs, and revenues. This flexibility makes it particularly useful for complex infrastructure projects that require adaptable modeling approaches. The software also supports scenario-based analysis, enabling evaluations under multiple conditions to facilitate decision-making in uncertain environments.

Another important aspect of OpenTESim is its ability to integrate external datasets, ensuring that real-world data can be incorporated into simulations for greater accuracy. This feature enhances its applicability to practical use cases, including large-scale energy and infrastructure developments. Furthermore, as an open-source platform, OpenTESim benefits from continuous contributions, ensuring transparency, iterative improvements, and alignment with the latest industry methodologies.

2.1.2. Cash Flow Analyses & NPV

To estimate supply chain component costs, different approaches are required depending on the nature of the infrastructure. While energy-related components such as wind turbines often employ a constant cost rate in €/MW (BVG Associates, 2019; Giampieri et al., 2024), this method as used by Bakker, 2024 is not directly applicable to port elements, where costs are influenced by factors such as structural dimensions, materials, and specific operational requirements. Consequently, a more tailored approach is needed to account for the diverse functionalities and physical characteristics of port infrastructure (Dragan et al., 2017).

Typically, cost estimation for supply chain components involves two primary categories: CAPEX and OPEX. For instance, onshore wind turbines have a typical CAPEX of approximately €1,000,000 per MW, while AC substations exhibit lower CAPEX values of around €50,000 per MW (Vieira et al., 2019, BVG Associates, 2019). For energy components, costs are typically derived by multiplying a constant rate by the capacity. However, for port infrastructure such as jetties, storage facilities, and quay walls, CAPEX is driven by physical scale, structural complexity, and site-specific conditions but also capacity-based metrics (Kaiser and Snyder, 2012).

OPEX is similarly calculated as a percentage of CAPEX for energy systems, but for port elements, OPEX can include maintenance, dredging, and operational staffing, which are influenced by the specific use case. Annual net project cash flows are then computed by aggregating all cash flow components, including CAPEX, OPEX, and revenues, where revenues depend on the type of activity (e.g., energy transshipment or cargo handling) (Ioannou et al., 2018, WFO, 2022).

Financial evaluation relies on the time value of money principle, which emphasizes that a euro today holds more value than a euro in the future due to inflation, opportunity cost, and risk. The calculation of NPV is central to this analysis, as it compares the present value of cash inflows and outflows associated with the project (Corporate Finance Institute, 2019a, Ye and Tiong, 2000). The NPV formula is given by:

$$\text{NPV} = \sum_{t=0}^{T} \frac{C_t}{(1+r)^t} \tag{2.1}$$

Where:

- C_t is the net cash flow at time t (which can be either positive or negative),
- r is the discount rate / WACC (reflecting the opportunity cost of capital or risk),
- T is the total number of periods under consideration.

The NPV allows decision-makers to assess whether a project is financially viable by evaluating whether the sum of discounted future cash flows exceeds the initial investment. If NPV is positive, the project is considered profitable, while a negative NPV suggests that the project would result in a net loss (Myers, 1974).

Inflation also plays a significant role by measuring the rate at which prices for goods and services rise over time, eroding the purchasing power of money. It impacts both the real cost of capital and future cash flows (MAN Group, 2021). However, in many techno-economic assessments found in the literature, inflation is less transparently addressed compared to the discount rate. This lack of clarity can hinder cross-study comparisons, as variations in inflation accounting can significantly affect results, such as the LCOE or port transshipment costs (Joskow, 1976, Santos et al., 2016).

In summary, cash flow analyses are fundamental in techno-economic assessments, but methodologies must adapt to the nature of the components being evaluated. While constant cost rates provide a transparent and efficient method for estimating energy-related components, port infrastructure requires a more nuanced approach. Furthermore, consistent treatment of discount rates and inflation is essential to enhance the comparability and reliability of study results.

2.1.3. LCOE in Multi-Industry Contexts

The Levelized Cost of Energy is a widely used metric in the energy sector to assess the cost-effectiveness of energy production technologies. It represents the per-unit cost (typically in €/MWh) of building and operating a generating plant over an assumed financial life and duty cycle. LCOE is calculated by dividing the total lifetime costs (CAPEX and OPEX) by the total energy produced over the plant's operational period (Ueckerdt et al., 2013, Corporate Finance Institute, 2020). The formula for LCOE is:

$$LCOE = \frac{\sum_{t=1}^{n}(\text{CapEx}_t + \text{OpEx}_t)(1+r)^{-t}}{\sum_{t=1}^{n} E_t(1+r)^{-t}}$$

Where:

- CapEx_t is the capital expenditure in year t,
- OpEx_t is the operational expenditure in year t,
- E_t is the energy produced at year t,
- r is the discount rate,
- n is the project's lifespan.

As shown in the chart in figure 2.1, LCOE across Europe varies between projects (dots) but overall are continuing to reduce significantly over time (BVG Associates, 2019). The LCOE has been back-calculated based on assumptions of full-life revenue and transmission costs, where applicable, as well as the auction price).

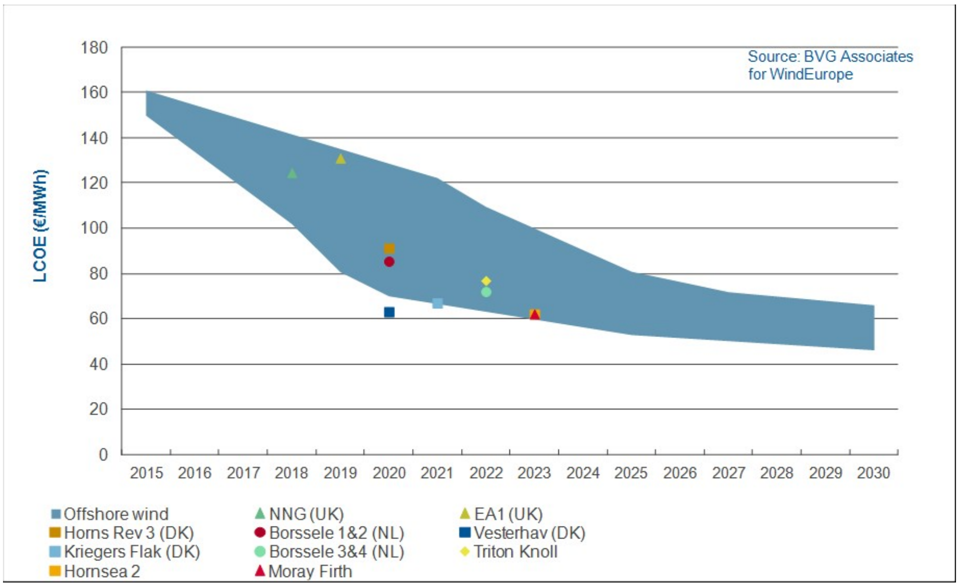


Figure 2.1: LCOE across Europe (BVG, 2019)

A significant factor influencing LCOE is cost reduction, which can stem from decreased capital and operational expenses, increased energy production, or changes in financing conditions. The key drivers of LCOE reduction include:

- Site Conditions: Projects in deeper waters require more expensive foundations and increased installation costs. Favorable ground conditions, such as homogeneous stiff clay, can provide cost benefits by allowing a broader range of foundation solutions with high long-term stability. Adverse conditions, including rock or boulders, often necessitate costly alternative designs and installation methods (El Hamdani et al., 2021).
- Environmental Factors: Wind speed, wave height, and tidal variations directly impact energy production and operational costs. Higher wind speeds increase yield but may require reinforced designs, while storm conditions and tidal variations add complexity to maintenance and installation operations (X. Li and Zhang, 2020).
- Distance to Shore and Transmission Costs: Offshore projects further from shore incur higher operational and grid connection costs. Beyond 60 km, service operation vessels (SOVs) become more cost-effective than daily crew transfer vessels (CTVs). Increased transmission distances also lead to higher capital and operational expenditures (Higgins and Foley, 2013).
- Market Mechanisms: The shift from fixed-price support mechanisms to competitive auctions has driven LCOE reductions by increasing market efficiency and cost competition among developers and suppliers (Kenis, 2023).
- Supply Chain Maturity: The offshore wind supply chain has evolved, with larger players taking on broader scopes, reducing costs through economies of scale, standardization, and process efficiency. Certain components, like turbines, have limited global suppliers, restricting competition, whereas elements like foundations and cables benefit from a geographically diverse supplier base (WindEurope, 2024).
- Technology Development: The rapid increase in turbine ratings, from 2 MW two decades ago to over 10 MW today, has significantly reduced LCOE. Larger turbines drive down per-MW costs for foundations, installation, and operations while capturing more energy per installed MW. The incorporation of digitalization, automation, and artificial intelligence further enhances operational efficiency and cost reduction (Bajaj and Sandhu, 2017).

Over time, governments have transitioned from fixed market mechanisms to competitive bidding processes, increasing cost efficiency in offshore wind development. Additionally, the incorporation of digital technologies and automation has further driven down operational costs.

While this method provides a clear and standardized way to compare different energy technologies, it has limitations when applied to multi-industry contexts like the one under consideration, which combines energy production with port infrastructure functionalities (Hansen, 2019).

In our case, the inclusion of port infrastructure, such as storage facilities and quay walls, introduces elements that are not directly related to energy production, yet are crucial for the operational success of the system. Moreover, revenues in the port sector, including cargo handling and transshipment activities, do not follow the same patterns as energy generation, making it difficult to incorporate these elements into a singular LCOE calculation. As a result, the LCOE metric is not well-suited for a combined analysis, as it fails to account for the complexity and diversity of costs and revenues associated with both the energy and port components. A more integrated approach, considering the unique characteristics of each sector, is required to evaluate the overall financial feasibility of the combined energy and port infrastructure. The use of methods NPV allows for a more comprehensive evaluation by capturing the distinct cost structures and revenue streams from both industries in a manner that LCOE cannot.

A similar metric, the Levelized Cost of Hydrogen (LCOH), is used for hydrogen production (Lehmann et al., 2022, European Union, 2023). The formula for LCOH is:

$$LCOH = \frac{\sum_{t=1}^{n} (\text{CapEx}_{H2,t} + \text{OpEx}_{H2,t})(1+r)^{-t}}{\sum_{t=1}^{n} H2_t (1+r)^{-t}}$$

Where:

- $\text{CapEx}_{H2,t}$ and $\text{OpEx}_{H2,t}$ represent the capital and operational expenditures for hydrogen production,
- H2_t is the hydrogen produced at year t.

Both LCOE and LCOH are impacted by supply chain efficiency, especially in offshore energy systems, where transmission losses and capacity factors should be considered. These metrics, along with other financial elements like WACC, IRR, and discount rates, provide a comprehensive assessment of financial viability.

2.1.4. Pros and Cons of NPV And LCOE

Net Present Value is a widely used method in financial analysis due to its simplicity and ability to capture the time value of money. It provides a clear indication of whether a project will generate more value than its cost by comparing the present value of cash inflows and outflows. One of the main advantages of NPV is its straightforwardness in evaluating profitability. Additionally, it helps decision-makers understand the long-term financial implications of a project, considering factors like discount rates and inflation (Bosri, 2016; Marchioni and Magni, 2018).

However, NPV has its limitations. It assumes a constant discount rate over time and does not account for uncertainties or the flexibility inherent in many investment projects (Trigeorgis and Reuer, 2017).

LCOE is commonly used to evaluate energy systems due to its ability to compare the value of energy production with values found in literature and practice. However, it has the limitation of not accounting for non-energy-related factors. In cases where these factors can be quantified, the use of a LCOX can be considered to assess their feasibility (Peecock et al., 2024).

2.1.5. WACC and Discount Rate in Techno-Economic Assessments

The Weighted Average Cost of Capital and the discount rate r are essential components in financial evaluations for offshore infrastructure projects, particularly in techno-economic assessments. Both concepts are integral for assessing the viability and profitability of projects by accounting for the time value of money and risks associated with the investments (Corporate Finance Institute, 2019b, Corporate Finance Institute, n.d.).

Weighted Average Cost of Capital:

The WACC represents the average rate of return a company must pay to all its stakeholders (equity holders, debt holders, etc.) weighted by their respective shares in the company's capital structure. It combines the cost of debt and the cost of equity to reflect the overall cost of financing for a project or business. WACC is particularly useful when evaluating corporate-level investments or long-term projects where the capital structure remains stable (Corporate Finance Institute, 2019b).

The WACC is used as a discount rate in NPV calculations to evaluate the profitability of projects that involve external financing (e.g., loans or equity investments). The formula for WACC is as follows:

$$\text{WACC} = \frac{E}{V} \cdot r_E + \left(1 - \frac{T}{V}\right) \cdot r_D \cdot (1 - T) \tag{2.2}$$

Where:

- E is the value of equity,
- V is the total value of the company's financing (equity + debt),
- r_E is the cost of equity,
- r_D is the cost of debt,
- T is the corporate tax rate.

WACC reflects the minimum return a company must earn to satisfy all its stakeholders. A lower WACC is often seen as a sign of a less risky project or company, whereas a higher WACC indicates higher perceived risk.

Discount Rate r:

The discount rate r is a broader term and refers to the rate used in NPV calculations to discount future cash flows to present value. While WACC can serve as a discount rate in some contexts (especially when analyzing corporate investments), the discount rate r can also represent the cost of capital specific to a project, a required rate of return, or a reflection of the risk profile of the specific infrastructure being assessed (Corporate Finance Institute, n.d.).

When evaluating infrastructure projects, the discount rate is typically chosen based on the project's risk, the time horizon, and the cost of capital. If a project is financed entirely by debt or equity, the cost of debt or the required return on equity may be used as the discount rate. Alternatively, the discount rate could represent the required return on a portfolio of projects with similar risk.

While WACC is the preferred method for discounting when using both debt and equity financing in a corporate structure, the discount rate r is flexible and can be tailored to specific projects or types of financing.

In summary, WACC is the appropriate discount rate when evaluating the overall cost of capital for a company or investment involving both debt and equity, as it reflects the weighted average cost of each capital component. In contrast, the discount rate r is a more flexible parameter that can be tailored to the specific financial characteristics, risk profile, or strategic priorities of a given project (Magni, 2015). While WACC is often preferred for firm-wide valuation and is typically derived from market-based inputs such as cost of debt, equity returns, and capital structure, obtaining reliable data for WACC can be challenging, particularly for new projects, non-listed entities, or markets with limited transparency. On the other hand, setting an appropriate discount rate r can be more subjective, but may offer greater practicality in cases where precise capital cost inputs are unavailable or when a normative or scenario-based approach is more appropriate (Garvin and Cheah, 2004).

2.2. Literature on Multi-functionality Assessment

Multi-functionality is essential for developing future-proof infrastructure, with applications extending beyond energy to multiple sectors. Mazza, 2023 emphasizes the importance of integrating various marine activities, such as offshore wind and hydrogen production, within offshore infrastructure. By combining multiple functions in a single platform, these modular and mobile solutions optimize space use and enhance sustainability, providing both economic and operational benefits.

Similarly, Strbac et al., 2016 underscores the value of multi-functional energy infrastructure, particularly for hydrogen production. They argue that systems integrating generation, storage, and conversion services offer crucial flexibility and reliability.

Ninan et al., 2024 takes a broader "system of systems" approach, advocating for infrastructure that combines multiple services to reduce costs and increase flexibility. This integration helps absorb supply intermittency and mitigate revenue volatility, a concept also explored by Awad et al., 2024.

These studies collectively demonstrate the growing relevance of multi-functionality for ensuring resilient, adaptable, and economically viable infrastructure. While the concept remains underexplored in offshore islands, multi-functionality has been widely applied in various industries. Different sectors have developed methods like Multi-Criteria Decision Analysis to evaluate and prioritize multi-functional designs, offering structured approaches to balance competing objectives. These frameworks are well-suited to address the complex challenges posed by integrating multiple functions in offshore infrastructure projects.

2.2.1. Multi-Criteria Decision Analysis (MCDA) and Its Application to Evaluating Functionalities of Offshore Islands

Overview of MCDA

MCDA, also known as Multi-Criteria Decision-Making, is a structured approach used to evaluate alternatives based on multiple, often conflicting, criteria. It is particularly valuable in complex decision-making scenarios where trade-offs between different objectives must be systematically analyzed (Cinelli et al., 2020).

By explicitly defining evaluation criteria and assigning relative importance to them, MCDA enhances decision transparency and ensures that the chosen alternative aligns with strategic priorities. This makes it widely applicable across sectors such as infrastructure development, energy planning, and logistics.

General Steps in MCDA

MCDA follows a structured process to ensure consistency and objectivity in decision-making. The key steps include (Vanderpooten, 1989, Caprace et al., 2025, Cinelli et al., 2020):

1. Define the Decision Context: First, identify the problem or decision that needs to be addressed. Establish clear goals and objectives that need to be achieved. Also, determine the scope of the analysis by considering relevant stakeholders and constraints that may impact the decision.
2. Identify Alternatives: Develop a comprehensive list of potential solutions, projects, or strategies that could address the decision problem. Ensure that these alternatives are well-defined and, where possible, mutually exclusive to avoid overlap.
3. Determine Evaluation Criteria: Identify the key factors that will be used to evaluate each alternative. These factors can be both quantitative, such as cost or efficiency, and qualitative, such as social acceptance or environmental impact. The criteria should be independent, comprehensive, and directly relevant to the decision context.
4. Assign Weights to Criteria: Weights represent the relative importance of each criterion in the decision-making process. Various methods can be applied to assign weights, including expert judgment, pairwise comparisons (e.g., Analytic Hierarchy Process), or statistical techniques.
5. Score Each Alternative Against the Criteria: Evaluate how each alternative performs relative to the established criteria. Scores can be derived from empirical data, expert assessments, or mathematical models. If necessary, standardization techniques should be applied to ensure comparability across criteria that may have different scales.
6. Aggregate Scores to Rank Alternatives: Once the scores are assigned, combine them using their respective weights to calculate an overall ranking of alternatives. Various MCDA methods can be used, such as the Weighted Sum Model, which aggregates the weighted scores linearly; the Analytic Hierarchy Process, which uses pairwise comparisons to determine relative priorities; PAPRIKA, which uses structured pairwise rankings; and outranking methods such as ELECTRE or PROMETHEE, which compare alternatives non-compensatorily.
7. Perform Sensitivity Analysis: Conduct sensitivity analysis to examine how changes in the criteria weights or input values impact the ranking of alternatives. This step helps assess the robustness of the decision and identifies key factors that have a significant influence on the outcome.
8. Interpret and Validate Results: Review the ranked alternatives to ensure that the results align with the original decision objectives. Finally, discuss the results with relevant stakeholders to validate the final decision and ensure it meets their expectations.

Application of MCDA to Multi-functional Offshore Islands

Offshore artificial islands, such as Princess Elisabeth Island, require a careful evaluation of potential functionalities, balancing technical feasibility, economic viability, and logistical efficiency. MCDA provides an ideal framework for this assessment by:

- Systematically prioritizing energy operations, cargo handling, and logistical functions based on predefined criteria.
- Ensuring that selected functionalities align with financial constraints and long-term industry trends.
- Facilitating transparent decision-making and stakeholder engagement.

By applying MCDA, decision-makers can develop a methodology to select the functionalities of offshore infrastructure projects (Mahdy and Bahaj, 2018). MCDA provides a framework for evaluating potential functions to include in the design of offshore islands. At its core, MCDA is a systematic decision-support method that helps to analyze alternatives against a set of defined criteria, allowing for a transparent evaluation of trade-offs. (Z. Zhang and Balakrishnan, 2021).

This method is relevant for multi-functionality assessments because it accommodates both quantitative and qualitative criteria. For example, in the case of offshore islands, quantitative factors might include the costs of infrastructure or logistical efficiency, while qualitative factors might encompass stakeholder priorities or environmental considerations (Guitouni and Martel, 1998).

Applications of MCDA Across Industries

MCDA has been successfully applied across various industries to evaluate multi-functional systems, offering valuable insights for infrastructure development, resource allocation, and operational optimization:

- Transportation Hubs: MCDA has been used to prioritize investments in transport infrastructure, such as airports and ports, by evaluating criteria like passenger capacity, environmental impact, and economic viability (Panaro et al., 2023).
- Construction hubs: Soltani et al., 2024 applied MCDA to assess construction hubs by weighing factors such as land use efficiency, connectivity, and resources proximity.
- Environmental Management: MCDA has been employed to address ecological trade-offs in land use planning (Langemeyer et al., 2016).

By leveraging MCDA, these industries have been able to make informed, transparent, and balanced decisions, highlighting its potential for assessing multi-functionality in offshore island designs.

2.2.2. Other Methods

Ros et al., 2012 use the Balanced Scorecard (BSC) to evaluate multi-functional port areas, categorizing activities under financial, customer, internal process, and learning perspectives. While effective for strategic assessments, the BSC approach falls short in addressing the unique challenges of offshore environments, such as energy integration. Nassar et al., 2020 assess the potential of multi-use offshore platforms for integrating energy, aquaculture, transport, and leisure. This study provides valuable insights into the integration of diverse functionalities on offshore platforms, though it focuses more on technological integration rather than the comprehensive evaluation of economic feasibility and risk management.

Although useful, they lack standardization, which is one of the primary objectives. Additionally, their applicability is limited when addressing cross-industry multi-functionality.

2.3. Standardization Across Industries

The necessity of standardization in techno-economic assessments has been highlighted since it enhances comparability across studies. This section explores international and industry standards within the offshore and ports industry in greater detail.

2.3.1. Standardization in the Offshore energy Industry

Standardization is crucial for effective communication and collaboration in offshore projects. However, no single international standard encompasses the entire supply chain. Various relevant standards are outlined, including:

- ISO 19008:2016 (Oil and Gas Industry)
- IEC 81346-1:2022 (Industrial Systems)
- ISO 16739-1:2018 (Industry Foundation Classes)
- AACE International 18R-97 (Cost Estimate Classification System)
- TNO's Energy System Description Language (esdl)

ISO 19008: Standard Cost Coding System for Cost Estimation

ISO 19008 is an internationally recognized standard that provides a systematic framework for the classification and coding of costs associated with the full life cycle of oil and gas production and processing facilities. Developed by ISO/TC67/WG4 and issued in August 2016, it aims to standardize cost estimation, facilitate benchmarking, and enhance data exchange across organizations. By implementing a uniform cost coding system, ISO 19008 seeks to improve transparency, comparability, and consistency in financial assessments across various infrastructure projects (Landerud and Zöllner, 2022).

The structure of ISO 19008 is organized into a main document and three normative annexes, each defining a specific hierarchical classification facet: the Physical Breakdown Structure, the Standard Activity Breakdown, and the Code of Resource. These facets enable a comprehensive classification of costs, activities, and physical quantities. The PBS provides a hierarchical framework for categorizing infrastructure components, the SAB classifies project activities and phases, while the COR focuses on resource-based classification, including materials, labor, and equipment.

ISO 19008 is widely used in cost accounting, project estimation, and financial modeling for offshore energy infrastructure. It supports the estimation of CAPEX and OPEX, which are critical for financial planning and feasibility studies. The standard is designed to be applicable across various project phases, from exploration and development to production and eventual decommissioning. Moreover, it allows organizations to benchmark costs and exchange data efficiently by adhering to a unified methodology.

Despite its structured approach and broad industry adoption, ISO 19008 exhibits certain limitations, particularly in its treatment of port infrastructure. While the standard acknowledges port infrastructure at a high level within the PBS framework, it lacks detailed classification for port-specific elements such as breakwaters, quay walls, jetties, and dredging activities. Given the growing role of ports in offshore energy projects, the absence of these elements represents a significant gap in the standard's applicability. The lack of granularity in port-related cost classification reduces the effectiveness of ISO 19008 when applied to projects that integrate offshore energy hubs with logistical and maritime components (Bakker, 2024).

Another limitation of the standard lies in its generalization of transport and installation activities. While it includes broad categories for offshore construction, marine operations, and logistics, these classifications do not account for the variability of specific transport and handling requirements in port-based energy infrastructure. For instance, the installation of subsea pipelines or offshore wind components often requires specialized port facilities, yet the cost elements related to these activities are insufficiently detailed within the existing coding system. This omission can lead to inconsistencies in cost estimation for projects that involve extensive port-based handling of offshore energy components.

In addition to port-related gaps, the PBS within ISO 19008 appears to be outdated for offshore energy applications. While certain elements related to hydrogen infrastructure have been incorporated into the coding system, other critical components such as BESS are notably absent. The increasing integration of BESS in offshore wind and hybrid energy projects highlights a crucial shortcoming of the current standard, as energy storage plays an essential role in balancing supply and demand fluctuations in renewable energy systems. The lack of specific classifications for BESS within the PBS restricts the applicability of ISO 19008 in contemporary offshore energy developments, necessitating updates to reflect advancements in energy storage technology.

In summary, ISO 19008 serves as a valuable tool for standardizing cost estimation in offshore energy projects by offering a hierarchical classification system for cost elements. However, its limited focus on port infrastructure, the lack of detail in transport-related costs, and the absence of comprehensive classifications for port-based offshore energy logistics reduce its applicability in integrated offshore-port projects. Additionally, the outdated PBS structure, particularly its exclusion of BESS and other emerging offshore energy components, limits the standard's relevance for modern energy transition projects. Future adaptations of the standard could benefit from more granular classifications that reflect the evolving role of ports and energy storage in offshore energy developments, thereby enhancing the precision and relevance of cost estimation in complex maritime infrastructure projects.

IEC 81346-1:2022

IEC 81346-1:2022 offers principles for structuring industrial systems, installations, and equipment across various technical fields. It emphasizes consistency in reference designations, improving communication and documentation (Balslev and Barré, 2023).

ISO 16739-1:2018 (IFC)

ISO 16739-1:2018 (IFC) standardizes data models for the construction industry, promoting interoperability among software used in architecture, engineering, and construction. It ensures data consistency and improves collaboration across stakeholders ("ISO 16739-1:2024 Industry Foundation Classes (IFC) for Data Sharing in the Construction and Facility Management Industries — Part 1: Data Schema", 2024).

AACE International 18R-97

The AACE International 18R-97 system classifies cost estimates based on project maturity, with five classes offering varying accuracy ranges. This system standardizes cost estimation practices, enhancing cost management and project control (Peter Christensen et al., 2005).

Energy System Description Language (esdl)

TNO's esdl provides a standardized method to describe energy systems, addressing the offshore industry's challenges. It enables representation of energy components, consumption profiles, and cost assessments, improving interoperability among tools and enhancing data comparison across studies. Yet as described by Bakker, 2024, the model has several limitations: it lacks a clear distinction between DC and AC cables, relying only on naming conventions, which can lead to errors. It also doesn't provide a detailed breakdown of standard activities, limiting accurate timeline and dependency modeling. Resource integration is oversimplified, as vessels for installation are only included in CAPEX, hindering resource allocation and scheduling. The absence of open-source techno-economic modeling in ESDL requires external models, which are not always available. Lastly, the integration with pyESDL is not user-friendly, restricting advanced data analysis and automation (North Sea Energy, 2022, Bakker, 2024).

2.3.2. Standardization in the Ports & Shipping Industry

While no single international standard covers the entire scope, several relevant standards can be applied across port-related components. These standards include:

- ISO 9001:2015 (Quality Management Systems)
- ISO 50001:2018 (Energy Management Systems)
- CEMT Guidelines (European Conference of Ministers of Transport)
- PIANC Design Guidelines for Ports and Harbors
- ISPS Code (International Ship and Port Facility Security Code)

ISO 9001:2015 (Quality Management Systems)

ISO 9001:2015 is a widely recognized standard for quality management systems, applicable to both energy and port infrastructure. It focuses on improving organizational efficiency, ensuring that operations meet customer requirements and are continually optimized. For offshore island projects with port functions, this standard ensures high-quality delivery of infrastructure and services (Iso, 2015).

ISO 50001:2018 (Energy Management Systems)

ISO 50001:2018 outlines best practices for establishing an energy management system. For offshore islands focusing on energy production, storage, and logistics, this standard helps optimize energy use, reduce costs, and ensure compliance with regulatory standards related to energy efficiency (Poveda-Orjuela et al., 2019).

CEMT Guidelines (European Conference of Ministers of Transport)

CEMT guidelines refer to a set of recommendations and standards issued by the CEMT, an intergovernmental organization focused on improving transportation across Europe. The guidelines typically cover various aspects of transport policy, infrastructure development, safety regulations, and environmental sustainability within the transport sector (Koedijk, 2020).

PIANC Design Guidelines for Ports and Harbors

The PIANC guidelines are essential for the design and development of port infrastructure, focusing on dredging, terminal design, and environmental impact mitigation. For offshore islands, these standards ensure that port facilities can accommodate large vessels and cargo while maintaining environmental sustainability (Heffron et al., 2016).

ISPS Code (International Ship and Port Facility Security Code)

The ISPS Code establishes security measures for ports and ships. For offshore islands with port functions, it ensures that the facilities comply with international security standards, protecting them against threats and enhancing the safety of both the personnel and the infrastructure (Code, 2002).

These standards are essential for ensuring that offshore islands with integrated energy and port functions are developed efficiently, safely, and sustainably .

2.3.3. Evaluation of standards for Multi-functional offshore islands

ISO 19008:2016 provides a well-structured approach for cost coding of elements and operations, which has been previously assessed by Bakker, 2024. However, the standard lacks sufficient detail for certain elements. Additionally, as the last update of the ISO code was in 2016, it does not account for more recent developments in this rapidly evolving industry. For this study, the ISO code will serve as the foundation for the cost estimation model, but it does not provide the level of detail needed for port infrastructure elements and operations.

Multiple guidelines exist for port infrastructure, with useful ones being PIANC and CEMT, but none of them incorporate a cost coding system for port infrastructure. According to MTBS expertise, no standard is currently used for their cost modeling. A similar system to that of MTBS might be employed for cost modeling of port infrastructure and operations in this study.

2.4. Techno-Economic Assessment of Offshore Wind Projects

Table 2.1 provides an overview of recent techno-economic assessments in the offshore wind energy sector, highlighting which financial metrics are used and how they are applied. Despite the widespread use of key financial metrics such as LCOE and NPV, there is significant variation in methodologies. Discount rates applied in these studies range from 4% to 10%, with some studies not specifying the rate at all. While LCOE is commonly used, there is no standardized approach for calculating energy production. Additionally, the components included in FCF are often inconsistently defined, typically limited to CAPEX and OPEX, with some studies omitting a detailed breakdown of OPEX. In contrast, studies employing NPV tend to offer greater transparency in both the definition of FCF and the justification of the discount rate.

Table 2.1: Overview of recent techno-economic assessments and the use of key financial metrics

Literature	LCOE	NPV	Discount Rate / WACC
Thommessen et al., 2021b	✓	×	Not specified
Gao et al., 2024	✓	×	7.6%
B. Li and DeCarolis, 2015	✓	×	10%
Roussanaly et al., 2019	✓	×	8%
Petracca et al., 2022	✓	✓	4–8%
Martinez and Iglesias, 2024	✓	×	Not specified
Jang et al., 2022	×	✓	8%
Lucas et al., 2022	×	✓	10%

Bakker (2024) and Van den Haak (2023) developed a structured approach to assessing the techno-economic feasibility of offshore wind projects by refining financial methodologies and expanding technical analyses. A significant contribution of their study was the introduction of a standardized notation system, which aimed to improve clarity in financial and technical assumptions, thereby facilitating industry-wide adoption of their methodology.

The financial methodology employed in their model centered around well-established economic evaluation tools, including NPV, the WACC, the IRR, and the payback period. NPV was used to determine the present value of future cash flows, adjusted using a discount rate that accounted for investment risk and the time value of money. The WACC was applied as the primary discount rate to accurately represent capital costs and associated risks. The IRR provided a measure of investment feasibility by identifying the discount rate that resulted in a zero NPV. Additionally, the payback period metric assessed the duration required to recover initial investments, offering further insights into project viability. To account for asset depreciation and divestment, the study applied a straight-line depreciation method, ensuring a systematic evaluation of remaining asset value over time. These financial evaluations were structured within profit and loss statements and balance sheets to provide an overview of project performance.

A key component of their methodology involved assessing supply chain efficiency, particularly for hybrid energy systems integrating hydrogen and electricity production. They proposed an efficiency formula that considered energy losses across different stages of offshore energy transport. This model incorporated industry data on cable transmission losses, hydrogen pipeline efficiencies, and electrolysis performance. Additionally, they addressed the Jevons Paradox, which suggests that efficiency improvements in energy systems may lead to increased overall energy consumption rather than reduced demand. By incorporating these efficiency considerations, their model provided a more comprehensive view of supply chain performance and potential cost implications.

Building on previous methodologies established by Van den Haak (2023), their study retained core financial analysis elements while expanding technical considerations. While the financial frameworks remained consistent, they introduced improvements such as dynamic adjustments to input variables, allowing for variations in wind farm configurations and multiple potential starting years. The supply chain configurations were expanded to include a broader range of offshore energy island designs, HVDC transmission systems, and centralized versus decentralized offshore platform conversions. Recognizing a critical gap in offshore energy island cost estimation, they developed a detailed financial model specific to these novel infrastructure projects, ensuring more accurate assessments of capital and operational expenditures.

Further methodological advancements focused on the integration of geospatial data, which enabled a more precise analysis of location-specific factors such as water depth and cable distances. This enhancement improved logistical planning and optimized offshore wind project layouts. Moreover, the study identified critical gaps in the literature, particularly regarding offshore Wind-to-Hydrogen systems. Compared to Wind-to-Power projects, fewer studies had explored the financial feasibility of offshore hydrogen production, necessitating a more balanced approach in future research.

To address the lack of standardization in techno-economic studies, they proposed a framework that allows for consistent comparison across different supply chain configurations. Their study also emphasized the importance of open-source models to improve transparency and enable collaborative development in techno-economic assessments. A notable improvement involved incorporating detailed transmission efficiencies and costs, refining the accuracy of financial evaluations and ensuring a more precise representation of offshore energy project feasibility.

The final step in their methodological framework was the development of an enhanced cost estimation model for offshore energy islands. This model incorporated all identified improvements, ensuring a robust and reliable assessment of economic feasibility. By combining financial analysis with refined technical components, the study provided a standardized approach to evaluating offshore wind and hybrid energy projects.

Their research will serve as the foundation for this study. Since the goal is to advance the standardization of financial assessments for offshore projects, it makes sense to adopt a similar workflow and standards. Bakker's cost estimation model for offshore islands provides a great starting point, which can be expanded to include port infrastructure elements.

3 Techno-Economic Analysis Modeling

Techno-economic analysis is a widely used methodology for evaluating large-scale systems, particularly in infrastructure and energy projects. By establishing a structured framework, this approach ensures a standardized evaluation process, enhancing consistency and comparability across different scenarios.

The TE analysis begins with system definition, where the scope and key functionalities of the system are identified. For a terminal, this includes cargo handling, transshipment, storage, and logistics. For an offshore hub, it encompasses energy generation, conversion, storage, and transmission. At this stage, it is also essential to establish design constraints and assess market demand forecasts, which include expected cargo volumes for terminal operations and energy production and storage requirements for offshore hubs.

Once the system is defined, the next step is supply chain inventorying, where all necessary components are identified. This includes defining both physical and financial characteristics of critical elements in offshore energy systems and seaports.

Following this, process modeling is conducted, focusing on the flow of mass or energy through the system. For instance, in offshore energy systems, this involves tracing energy generation from wind turbines, through conversion and storage, to final transmission to the mainland. This step ensures that all operational components are aligned to create a fully functional system.

The next phase is financial performance modeling, which involves inventorying system costs and revenues at both component and project levels. Establishing cash flows and applying key financial metrics such as LCOE, NPV, and IRR allow for assessing financial feasibility.

Finally, sensitivity analysis is performed to test system robustness under varying conditions. This step evaluates how financial feasibility is affected by changes in external factors such as market prices, operational costs, and demand fluctuations.

By following this structured framework, TE analysis provides a comprehensive assessment of a system's financial viability, ensuring that both technical and financial aspects are rigorously evaluated.

3.1. System Definition

The first step in techno-economic analysis is defining the system under consideration. This involves identifying the primary purpose of the system, its key functionalities, and the constraints that influence its design and operation. For offshore energy and port systems, system definition ensures a structured approach to assessing their feasibility and performance.

An offshore energy system typically consists of energy generation, conversion, storage, and transmission components. The system must accommodate varying energy sources, such as wind or wave power, and consider the infrastructure required for efficient energy transfer to the mainland. Design constraints include geographical conditions, grid integration requirements, and regulatory frameworks. Additionally, market demand forecasts must be incorporated by assessing expected energy production, storage capacity needs, and the long-term viability of energy exports or local consumption (Rumes et al., 2022).

A port system, on the other hand, encompasses cargo handling, transshipment, storage, and logistics operations. The system definition involves evaluating terminal capacity, vessel traffic projections, and operational constraints such as water depth, berth availability, and hinterland connectivity. Market demand forecasts play a crucial role in determining expected cargo volumes, the mix of commodities handled, and potential transshipment requirements (Ligteringen and Velsink, 2012).

Both offshore energy and port systems must align with financial and technical feasibility considerations. By establishing a clear system definition, the subsequent stages of supply chain analysis, process modeling, and financial assessment can be conducted in a more structured and coherent manner.

3.1.1. Supply Chain of Offshore Energy Systems

Efficient planning and implementation of offshore energy projects require a clear understanding of their supply chain components. This section presents a high-level overview of key elements involved in offshore wind energy and gas transmission systems, following a Physical Breakdown Structure (PBS) inspired by ISO 19008:2016 and adapted from Bakker, 2024. It should be noted that this overview covers only few components relevant to the techno-economic analysis. A more comprehensive breakdown, including additional components, the internal cost classification system, and the ISO 19008 cost codes, is provided in Appendix A. The ISO 19008 coding system is not applied in this research, due to its limited clarity and practical applicability.

Cost Coding and Level of Detail

To enable consistent communication and structured cost tracking, each element within the supply chain is assigned a unique cost code. These cost codes not only identify specific components but also implicitly define their level of detail.

The hierarchical structure of the codes is indicated by the use of dashes ('-'), where each additional segment represents a deeper level of granularity. This system facilitates clear communication of both scope and detail between stakeholders, especially when working across disciplines or organizations.

For example, an offshore wind farm may be denoted as `OFS-W`, while a more detailed component, such as a wind turbine within that farm, would be represented as `OFS-W-T`. This structure allows for scalable modeling and modular expansion of the supply chain breakdown.

Figure 3.1 provides an overview of offshore system components that are relevant to this research.

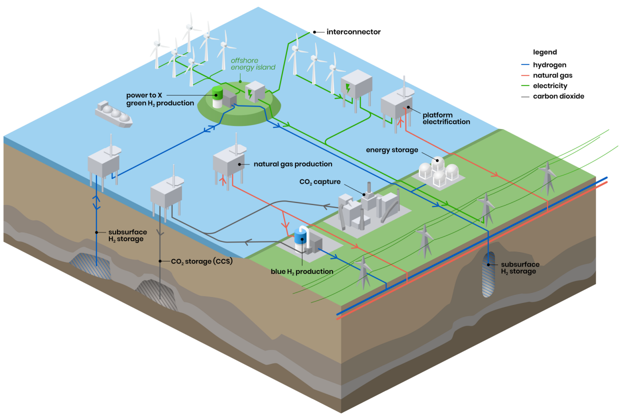


Figure 3.1: Overview of offshore activities including (1) sub-station and/or (2) electrolyser on an energy island (North Sea Energy, 2020)

Offshore Wind Energy Production and Transport

Offshore wind farms consist primarily of turbines, foundations, and inter-array cables. The turbines, often rated up to 15 MW (e.g., SG 14-222 DD and HaliadeX), are designed for high-efficiency energy conversion in challenging marine conditions (Siemens Gamesa, 2024; Vernova, 2024). They are mounted on foundations adapted to site depth, monopiles for shallow waters, jackets for mid-depths, and floating platforms for deeper sites (Thomsen, 2014; Wu et al., 2019). These structures are connected by inter-array cables that transport the electricity to an offshore substation, typically buried to reduce visual and environmental impact (Byrne and Houlsby, 2003).

AC Substation and Transport

Electricity from the turbines is collected at an AC substation, where its voltage is stepped up for efficient transport (Lei et al., 2024). From here, AC cables transmit the power to shore or to another offshore facility. These cables are made of copper or aluminum and are insulated for marine durability, achieving transmission efficiencies of up to 99% (Apostolaki-Iosifidou et al., 2019; Hamadi et al., 2019).

HVDC Converter and Transport

For long-distance transmission, the system integrates HVDC converters, which convert AC to DC (Lei et al., 2024). HVDC substations are installed offshore, reducing losses over distances where AC becomes inefficient. HVDC cables transmit this electricity with high efficiency (95–98%), although losses do increase with cable length (De Alegría et al., 2009).

Electrolysis System

Where hydrogen production is included, the system incorporates electrolyzers powered by offshore renewable energy. Technologies such as Proton Exchange Membrane, Alkaline, and Solid-Oxide electrolyzers offer varying trade-offs in terms of cost, response time, and efficiency (Lange et al., 2023; Nechache and Hody, 2021). Supporting systems include desalination units to provide pure water for electrolysis (Karagiannis and Soldatos, 2008), and compressors to store the produced hydrogen at high pressures.

Offshore Artificial Island

Energy islands offer several key benefits for offshore wind integration. First, they enable cost savings by allowing large-scale infrastructure deployment such as hydrogen production, which can be more economical than using multiple HVDC cables (Wingerden et al., 2023). Second, energy islands can accelerate deployment timelines by leveraging local supply chains, reducing construction time and improving efficiency (CopenhagenEnergyIslands, 2024). Third, they help optimize grid usage by reducing wind energy curtailment and enhancing power cable utilization (CopenhagenEnergyIslands, 2024).

Despite these advantages, offshore energy islands face several challenges, including high capital expenditures, limited construction experience, and logistical complexities. Different construction methods, such as sandy rock, caisson-based, or floating barrier islands, each come with trade-offs in terms of cost, durability, and feasibility.

At a structural level, energy islands typically consist of three main components: the island structural body, port infrastructure, and operational facilities. The structural body may include revetments, caissons, and sand berms. Port-related infrastructure often includes breakwaters, quay walls, and submerged barriers. Operational facilities comprise utility-related infrastructure such as cable and pipe landing systems.

Table 3.1: Associated components in the energy island cost estimation model per island type

Element	Type I: Rock Revetment	Type II: Caisson	Type III: Floating
Heavy side revetment	✓		
Light side revetment	✓		
Caisson		✓	
Rock berm under caisson		✓	
Sand in caisson		✓	
Breakwater (harbour protection)	✓	✓	
Sand inside island and harbour	✓	✓	
Quay wall	✓	✓	
Submerged breakwater			✓
Sand body below breakwater			✓
Floating barrier			✓
Floating barges			✓
Cable landing facilities	✓	✓	✓

3.1.2. Supply Chain of Seaports

Port functions on an offshore island primarily pertain to transshipment since no producers or end users are present on the island. The transshipment process involves transferring cargo between vessels or between vessels and storage facilities and possibly further transporting to the hinterland by pipelines.

Supply Chain Elements

Figure 3.2 illustrates a generalized seaport supply chain. This research focuses on the transshipment-related elements relevant to offshore islands.

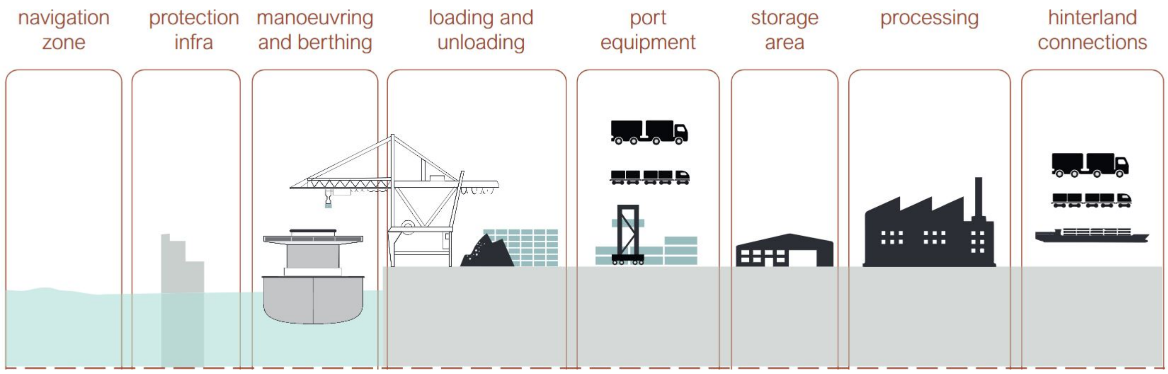


Figure 3.2: Port development and operations supply chain (modified from PIANC, 2019a, by TUDelft – Ports and Waterways, licensed under CC BY-NC-SA 4.0)

Navigation Zone

The navigation zone refers to the maritime area used by vessels to approach the port, including entry channels, fairways, and turning basins. For offshore islands, this area must account for factors such as water depth, tidal variations, and wave conditions to ensure safe and efficient navigation (I. C. Kim, 2012).

Protection Infrastructure

Protection infrastructure includes breakwaters, sea walls, and other structures that shield the port from adverse weather conditions, waves, and sedimentation. Offshore islands are especially vulnerable to extreme wave conditions, making robust protective measures essential to maintain port operability (J. Kim and Morrison, 2012, Kurt et al., 2015).

Manoeuvring and Berthing

Manoeuvring involves the movement of vessels within the port to approach berths safely. This includes tug assistance and pilotage. Berthing refers to the securing of vessels to the quay or jetty for loading and unloading. Offshore islands face unique challenges in this domain, such as limited space, strong currents, and wave action that could complicate these processes. Proper berth design and adequate fendering systems are crucial to address these challenges (Pluijm, 2014).

Key manoeuvring elements include turning basins, which are designated areas for vessels to turn safely, fairways and approach channels maintained through dredging, and marked navigation paths. Tug assistance and pilotage services ensure safe vessel movements in confined spaces. Mooring buoys and anchoring areas provide temporary holding positions before final berthing (Agerschou et al., 1983; Oelker et al., 2020).

Berthing elements include quay walls, jetties, and piers, which provide docking infrastructure for vessels. Dolphins serve as isolated mooring structures, while fender systems absorb berthing energy, protecting both ships and quay walls. Bollards and mooring hooks secure mooring lines, and gangways or access bridges facilitate movement between vessels and shore (G. Wang et al., 2023).

Loading and Unloading

The loading and unloading process involves transferring goods between vessels and storage facilities. For offshore islands, efficiency in cargo handling is paramount to minimize vessel turnaround times and operational costs. Equipment such as cranes, conveyor belts, and automated systems play a key role in achieving high throughput (Lee et al., 2014).

Cargo handling systems include ship-to-shore cranes for container operations, mobile harbor cranes for multipurpose handling, and bulk handling systems such as grab cranes and conveyor belts. Pipeline systems facilitate the transfer of liquid bulk cargo such as LNG, oil, or chemicals. RoRo ramps support the movement of vehicles and trailers (Marsudi et al., 2025).

Port Equipment

Port equipment encompasses all mechanical and automated tools required for cargo handling, including quay cranes, forklifts, and automated guided vehicles. Offshore islands require durable, low-maintenance equipment capable of operating in harsh marine environments. The selection of equipment significantly influences energy consumption and operational efficiency (Kosiek et al., 2021).

Storage Area

Storage areas act as temporary holding zones for cargo during transshipment. For offshore islands, these facilities are primarily short-term and designed to accommodate limited cargo volumes between vessel transfers. Space optimization, climate control for specific cargo types, and rapid accessibility are key design considerations (Muller and Prince, 1973, Aryai et al., 2021).

Processing

Processing involves the modification or packaging of goods, such as refining, assembly, or sorting. Offshore islands are primarily designed for transshipment rather than industrial or commercial processing, making this element largely irrelevant (Audigier et al., 2000; Ligteringen and Velsink, 2012).

Hinterland Connections

Hinterland connections encompass rail, road, and inland waterway links that facilitate cargo movement to and from the port. Offshore islands, by nature, lack direct hinterland connections. Instead, the focus is on efficient ship-to-ship transfers or transfers to storage areas for subsequent sea transportation (Guerrero, 2019).

Understanding the different types of port terminals is essential for designing efficient, functional, and sustainable port layouts. Each terminal type, ranging from container and general cargo to liquid bulk, Ro-Ro, and marinas, has distinct spatial, logistical, and environmental requirements. Factors such as berth orientation, proximity to urban areas, access to hinterland connections, and safety considerations like avoiding flight paths or hazardous zones are critical in planning terminal locations and infrastructure (Böse et al., 2011). Tables A.4 and A.5 in appendix A provide a structured overview of these requirements, including the necessary quayside equipment, storage facilities, and connections to road, rail, and inland waterways.

3.1.3. Standard Activity Breakdown (SAB)

The SAB categorizes key activities in offshore infrastructure projects from planning to decommissioning, as illustrated in Figure 3.3.

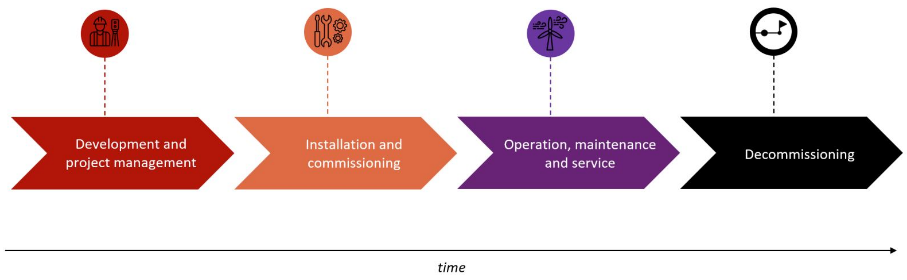


Figure 3.3: Activity Breakdown Schedule for an offshore project (Norman et al., 2008)

Development and Project Management

This phase includes securing permits, environmental assessments, engineering, financing, and stakeholder coordination up to the final investment decision. Ports require additional planning for infrastructure expansions (Norman et al., 2008).

Installation and Commissioning

Involves transportation, assembly, and testing of offshore structures such as wind turbines, subsea cables, and storage facilities. Ports facilitate logistics through specialized infrastructure (Voivedich Jr et al., 2001).

Operation, Maintenance, and Service (OMS)

OMS covers routine inspections, repairs, and performance optimization to maximize asset efficiency. Ports maintain handling equipment, vessel logistics, and compliance with safety regulations (Visser, 1993).

Decommissioning

Includes removal or repurposing of offshore structures and port facilities, ensuring environmental compliance and site restoration (Voivedich Jr et al., 2001).

3.2. Process Modeling: Flow of Mass

Process modeling is essential for understanding how a system operates and generates value. In the context of large infrastructure projects, such as offshore energy systems and port facilities, the system comprises multiple interconnected components that must function together. The system only becomes operational when all the necessary elements are in place, either through construction completion or through the initiation of OPEX, marking the beginning of revenue generation.

For example, in an offshore wind farm, the wind turbines must be installed, and AC and HVDC transmission systems must be built. However, the system does not become fully operational until these components are connected, allowing the transmission of electricity to the grid and the generation of revenue. Similarly, after several years of operation, if a critical component like an AC substation needs replacing, the system must temporarily shut down. Once the replacement is installed, the system resumes generating revenue.

3.2.1. Modeling the Flow of Mass

The flow of mass within the system is a critical element for validating the system's operation. This flow ensures that all subsystems are connected and functioning as designed, leading to the generation of revenue. For smaller systems, like a single wind turbine, the process is straightforward: the turbine only becomes operational when all its components, foundation, inter-array cables, tower, nacelle, and rotor blades, are assembled. However, when dealing with large-scale offshore energy systems, this process becomes significantly more complex, requiring careful consideration of all interconnected subsystems.

Example: Flow of Mass in a Large-Scale System

In large-scale offshore energy systems, such as offshore wind farms, the flow of mass refers to the movement of electricity through various stages of generation, conversion, and transmission. The system can be thought of as a directed graph (DG), where the nodes represent physical components, and the edges represent the directional flow of mass or energy between these components.

For instance, in an offshore wind farm, electricity is generated by multiple wind turbines and flows through inter-array cables to an AC substation. From there, the energy is transmitted via an AC export cable to an HVDC substation. The energy is then sent through a DC export cable to the onshore AC/DC substation, which connects to the grid. This step-by-step process ensures that the energy reaches the market and generates revenue.

The structure of the system is represented as a DG, which ensures that there are no cyclic dependencies between components. In this structure:

- Nodes represent all physical components of the system, including cables, which are modeled as nodes due to their associated CAPEX, OPEX, and lifetimes.
- Edges represent the directional flow of mass (e.g., electricity).
- The DG ensures that each node, except the starting and ending points, has at least two neighboring connections.

When the system is operational, the mass (electricity) flows through the interconnected nodes. For example in figure 3.6, even if the BESS is incomplete, the system can still operate as long as the HVDC substation is functional and electricity can flow through it to the grid.

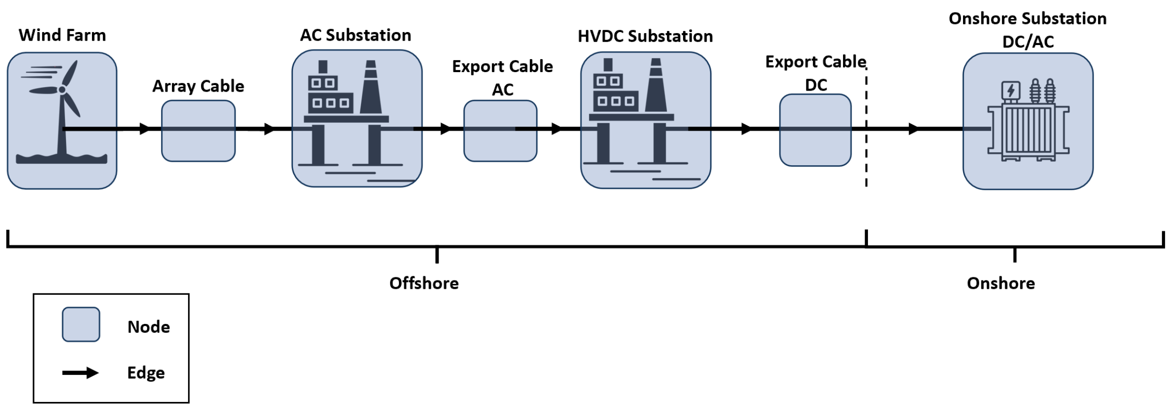


Figure 3.4: Flow of Mass: Concept Breakdown

3.2.2. Multiple Levels of Detail

To ensure that a system is operational, the flow of mass must be validated at multiple levels of detail. This hierarchical structure allows us to analyze the system from the highest level (the entire offshore energy system) down to the smallest components (such as individual wind turbines).

The operational hierarchy consists of four levels:

1. System level – The complete offshore energy system, including all subsystems and components.
2. Subsystem level – Key components such as the wind farm, AC substation, and export cables.
3. Element level – Individual components within a subsystem, such as the wind turbines within the wind farm.
4. Sub-element level – The smallest components, like the foundation, tower, nacelle, and rotor blades of each wind turbine.

This hierarchical model allows for a clear understanding of how each level contributes to the system's overall operation and revenue generation. It also provides a basis for more detailed analysis and optimization at each level.

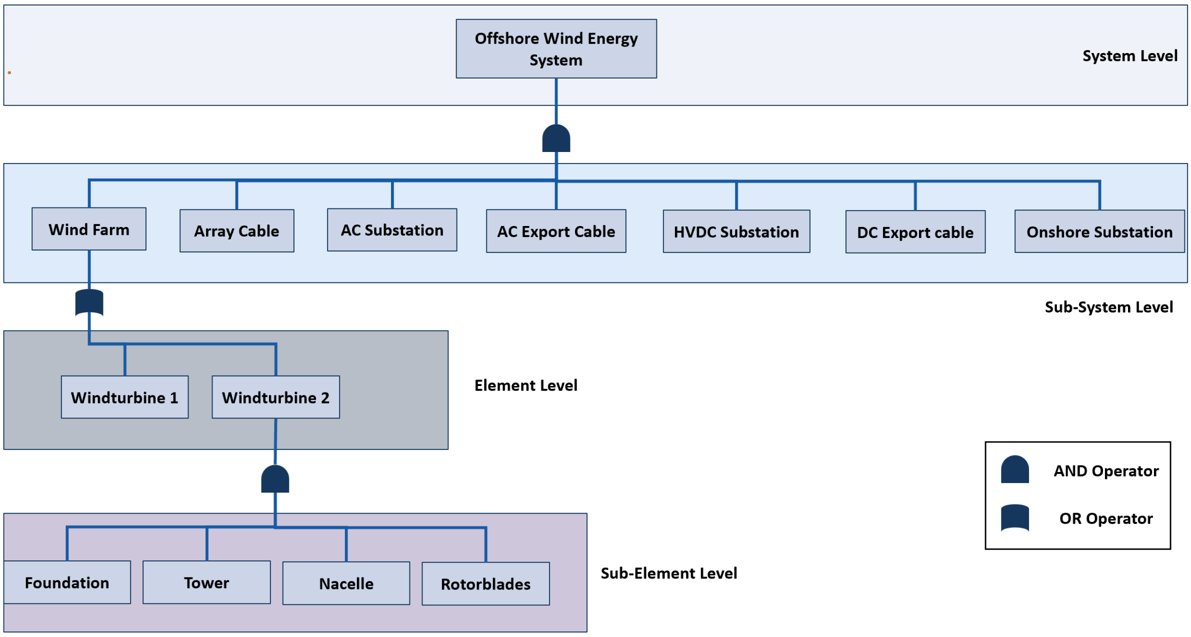


Figure 3.5: Process Modeling: Multiple Levels of Detail

AND/OR Logic in System Connectivity

To model the operational dependencies between different levels of the system, AND/OR gates are used. These gates define whether certain components need to be fully operational for the system to function or whether partial functionality is sufficient.

- AND gate – All connected components must be operational for the system to function.
- OR gate – Only one of several connected components needs to be operational for the system to function.

For example, in an offshore wind farm, the system can begin generating electricity as soon as at least one wind turbine is connected to the grid. This dependency is modeled as an OR gate, as only a portion of the system is required to be operational for the entire system to produce energy and generate revenue.

This hierarchical connectivity, with AND/OR gates, ensures that the flow of mass through the system is modeled accurately, reflecting the operational dependencies of each subsystem and element. The detailed analysis of system connectivity, coupled with the flow of mass model, provides a comprehensive understanding of the system's functionality and helps in identifying potential bottlenecks or inefficiencies.

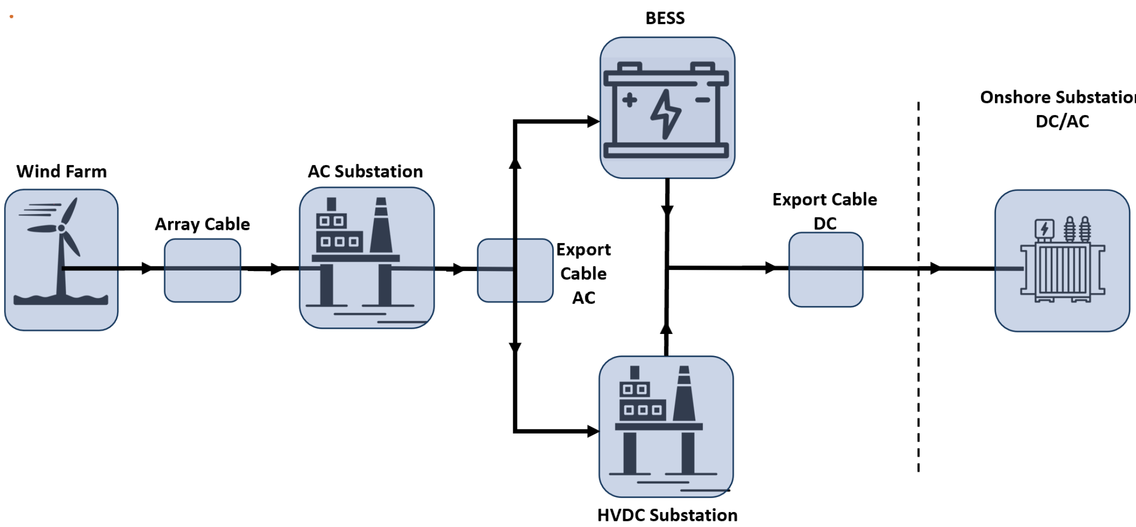


Figure 3.6: Flow of Mass: Alternative Routes for Operation

3.2.3. System Checks

System checks ensure that all components in large-scale infrastructure projects, such as offshore energy systems, are properly designed and interconnected. They validate that the system's physical properties, capacities, and operational characteristics align with performance requirements, preventing inefficiencies or failures.

Capacity Matching in Series and Parallel Systems

System configurations influence capacity distribution. In a series system, components are sequentially connected, and the total capacity is limited by the weakest element. For example, a 30 MW wind farm linked in series to an AC substation must have all components rated for 30 MW; any under-performing element compromises the system.

In a parallel system, components operate independently, and total capacity is the sum of individual outputs. For instance, an offshore wind farm with 10 turbines generating 3 MW each produces 30 MW overall. The substation and transmission infrastructure must be rated accordingly to handle the total load. If one turbine fails, the system still operates at 27 MW, ensuring continued functionality.

Proper sizing of components is critical. Oversized elements add unnecessary costs, while undersized ones limit performance. Ensuring accurate capacity matching enhances system stability and economic viability.

3.2.4. Mathematical Framework

The modeling of mass flow in an energy infrastructure network can be represented as a directed flow network, where components of the system are treated as nodes, and their interconnections define the edges. This approach enables the quantification of capacity constraints and flow limitations over time.

Mathematical Representation of Flow Networks

A flow network is formally defined as a directed graph $G = (V, E)$, where:

- V is the set of nodes (system components, such as pipelines, cables, or storage units),
- E is the set of directed edges (connections between components, each with a capacity limit).

Each edge $(u, v) \in E$ has an associated capacity $c(u, v) \geq 0$ that constrains the maximum possible flow between nodes u and v. The flow $f(u, v)$ along each edge must satisfy the capacity constraint:

$$0 \leq f(u, v) \leq c(u, v), \quad \forall (u, v) \in E. \tag{3.1}$$

Additionally, flow conservation holds for all nodes except the source and sink:

$$\sum_{w \in V} f(w, u) = \sum_{w \in V} f(u, w), \quad \forall u \in V \setminus \{s, t\}, \tag{3.2}$$

where s is the source (injection point of mass/energy), and t is the sink (final destination of the flow). This ensures that all incoming flow to an intermediate node is either stored or forwarded.

Temporal Evolution of Capacity

To incorporate time-dependent capacity evolution, let $C_t(v)$ represent the available capacity of node v at time t. The installed capacity evolves according to:

$$C_t(v) = C_{t-1}(v) + \Delta C_t(v) - D_t(v), \tag{3.3}$$

where:

- $\Delta C_t(v)$ represents newly added capacity at time t,
- $D_t(v)$ denotes decommissioned capacity at time t.

The system-wide operational capacity at time t is constrained by the maximum flow from source to sink, denoted as F_t:

$$F_t = \max \sum_{(u,v) \in E} f_t(u, v), \tag{3.4}$$

subject to:

$$f_t(u, v) \leq \min(C_t(u), C_t(v)), \quad \forall (u, v) \in E. \tag{3.5}$$

Ford-Fulkerson Method and the Edmonds-Karp Algorithm

The optimization problem is commonly solved using the Edmonds-Karp algorithm, a breadth-first search-based implementation of the Ford-Fulkerson method (Laube and Nebel, 2016).

The Ford-Fulkerson method is a greedy approach for computing the maximum flow in a flow network. Given a directed graph $G = (V, E)$ with a source node $s \in V$ and a sink node $t \in V$, each edge $(u, v) \in E$ has a capacity $c(u, v)$ that represents the maximum amount of flow that can pass through it. The objective is to determine the maximum feasible flow from s to t that respects capacity constraints and flow conservation at intermediate nodes (Ford and Fulkerson, 2015, Davies et al., 2023).

The method operates iteratively by identifying an augmenting path in the residual graph, which represents the available capacity for additional flow. Along this path, the flow is increased by the bottleneck capacity, which is the minimum residual capacity among all edges in the path. The process repeats until no more augmenting paths exist, at which point the flow is maximized.

A drawback of the general Ford-Fulkerson approach is that it may select augmenting paths inefficiently, leading to an exponential runtime in the worst case. The Edmonds-Karp algorithm refines this by enforcing a selection rule: it always chooses the shortest augmenting path (in terms of edge count) using Breadth-First Search. This guarantees that the algorithm runs in polynomial time, specifically $O(VE^2)$, making it significantly more efficient than the general case (Kyi and Naing, 2018).

The approach ensures that flow augmentation is performed in an optimal order, leading to fewer iterations compared to an arbitrary path selection strategy. This property is particularly useful in network flow problems where efficiency is critical, such as transportation planning and supply chain logistics.

Handling Multiple Sources: The Super-Source Transformation When dealing with multiple sources in the Edmonds-Karp algorithm, the problem is transformed into a single-source problem using a *super-source* S^* (Devi and Gopalakrishnan, 2021). This transformation is carried out as follows:

1. A new artificial node S^* is introduced.
2. Directed edges (S^*, S_i) are added for each original source S_i, with capacities $C(S^*, S_i)$ set to the total outflow capacity of each source.
3. The standard Edmonds-Karp algorithm is then applied, treating S^* as a unified source.

The residual network updates dynamically, and the final flow distribution can be extracted from the artificial edges (S^*, S_i), indicating the contribution of each original source to the total maximum flow. This transformation ensures that the multiple-source max-flow problem remains computationally tractable within the original Edmonds-Karp framework.

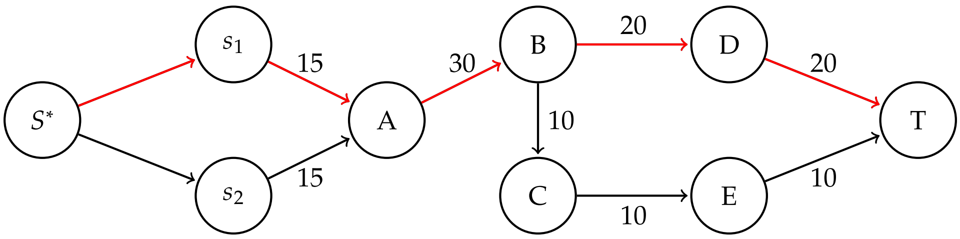


Figure 3.7: Flow network with a super-source S^* connecting multiple sources s_1 and s_2 to the network. The augmenting path is highlighted in red.

3.3. Project Cashflow Modeling

Large-scale infrastructure systems comprise multiple interdependent elements, each characterized by distinct financial parameters, including CAPEX, OPEX, and the WACC. However, conducting an independent cashflow analysis for each element would be impractical. Instead, a comprehensive financial model is required that consolidates all elements into a single system-wide cashflow analysis. This integration is complicated by varying economic lifetimes, construction durations, and depreciation rates, necessitating a structured approach to aggregating financial characteristics.

The first step involves collecting essential financial parameters for each system element. These include the investment start year, CAPEX investment, construction duration, and the share of investments allocated to each element. Additionally, the economic lifetime, escalation base year, and escalation rate are recorded to account for time-dependent cost variations. Other key financial characteristics include the yearly variable costs rate, insurance rate, depreciation rate, and decommissioning rate, which collectively influence the long-term financial performance of the system.

Subsequently, individual cashflow objects are generated for each element. These are then aggregated into a single project-level cashflow. Defining the overall project timeline is crucial in this process. Since individual elements may have different economic lifetimes than the project itself, adjustments are made to ensure alignment. For elements with a shorter lifetime, reinvestments are incorporated to extend their presence throughout the project duration. Conversely, for elements exceeding the project lifetime, divestments or residual values are accounted for at the project's end. The process of consolidating element-level cashflows into a project-wide financial model is illustrated in Figure 3.8.

In the current implementation of OPENTESIM, revenue streams are not yet incorporated into the cashflow modeling framework. Consequently, evaluations rely solely on cost-based metrics such as the LCOE and the LCOH. By integrating process modeling within OpenTESim, mass flow analysis can be incorporated to assess the system holistically. Once a continuous supply chain is operational, revenue generation becomes feasible. The inclusion of revenue streams within the cashflow model would enable evaluation using a broader set of financial metrics, including NPV and IRR, enhancing the comprehensiveness of project assessments.

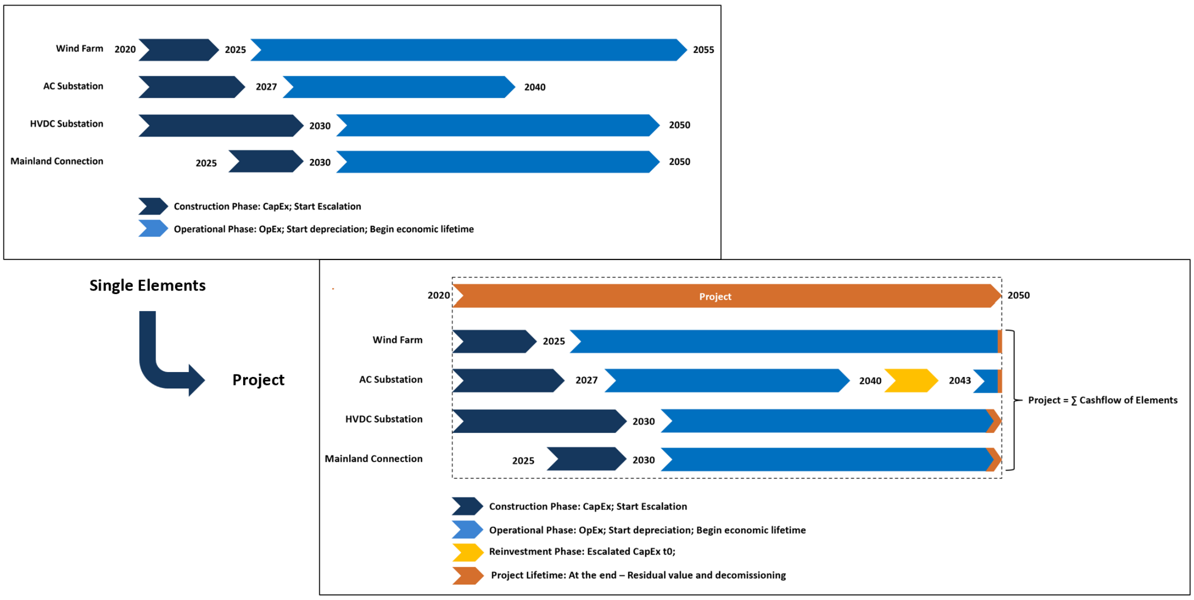


Figure 3.8: Cashflow modeling: Elements to Project object

3.3.1. Financial Assumptions and Timing

The OpenTESim software models the cash flow of an investment over time, incorporating key financial elements such as CAPEX, OPEX, depreciation, escalation, divestment, decommissioning, and NPV. The assumptions are in line with those applied by MTBS.

CAPEX represents the total investment required for the project, spread over the construction phase. The distribution is specified by the share of investments list, and CAPEX is escalated annually based on the escalation rate starting from the escalation base year, calculated as:

$$\text{Escalation Factor} = (1 + \text{escalation rate})^{(\text{year}-\text{escalation base year})}$$

OPEX is proportional to the escalated CAPEX, and is calculated using the yearly variable costs rate and insurance rate, both as percentages of the escalated CAPEX. The total OPEX for each year is given by:

$$\text{OPEX} = \text{yearly variable costs rate} \times \text{summed escalated capex} + \text{insurance rate} \times \text{summed escalated capex}$$

Depreciation is calculated by dividing the total escalated CAPEX by the asset's economic lifetime, assuming it occurs evenly over the asset's lifespan:

$$\text{Depreciation} = \frac{\text{summed escalated capex}}{\text{economic lifetime}}$$

The divestment value represents the revenue from selling the asset after depreciation, and is calculated as the remaining value of the asset after accumulated depreciation.

Divestment refers to the revenue realized from the asset's sale after depreciation. The divestment value is calculated as:

$$\text{Divestment} = \text{summed escalated capex} - \text{Accumulated Depreciation}$$

Decommissioning Costs are assumed to be a fixed percentage (decommissioning rate) of the total escalated CAPEX. These costs are incurred at the end of the asset's economic lifetime and are escalated similarly to other costs:

$$\text{Decommissioning Cost} = \text{decommissioning rate} \times \text{summed escalated capex}$$

NPV is used to evaluate the value of future cash flows. The NPV of each cashflow is discounted using the WACC with the following formula:

$$\text{NPV} = \frac{\text{Cashflow}}{(1 + \text{WACC})^{(\text{year}-\text{npv base year})}}$$

The cumulative NPV is the sum of the discounted cashflows across the asset's lifetime.

Other Assumptions include the economic lifetime of the asset, the year in which investment starts, the duration of the construction phase, and the share of investments allocated across the construction years. These parameters help define the financial performance of the asset over its life cycle.

3.3.2. Current Model Method

In the current model, the elements considered include CAPEX, OPEX, depreciation, escalation, reinvestments, residual value, and decommissioning. Depreciation and decommissioning are part of OPEX, reflecting ongoing operational costs. Residual value and reinvestments, on the other hand, are part of CAPEX, representing investments required to maintain or extend the system's lifespan. Escalation applies to both CAPEX and OPEX to account for inflation over the project's lifetime.

The free cash flow (FCF) is calculated as the sum of CAPEX and OPEX over the project's lifetime. Since CAPEX and OPEX are associated with costs, the NPV of the project generally decreases over time. However, this trend is interrupted in the final year when the residual value is added, which increases the NPV.

The formula for free cash flow is:

$$FCF = \text{CAPEX} + \text{OPEX}$$

The NPV at time t is given by:

$$NPV_t = \sum_{i=0}^{t} \frac{FCF_i}{(1 + WACC)^i}$$

Example: Single Wind Turbine

Figure 3.9 shows the timeline of a 50-year project for a single turbine with an economic lifetime of 30 years. After 30 years of operation, reinvestments are made to maintain functionality. At the end of the project life, the costs for decommissioning (which are significant OPEX) and the residual value (positive CAPEX) are applied. The NPV accumulates over time and decreases, with a noticeable increase at the end due to the residual value. The following assumptions were made for the project: the total CAPEX investment is €2,914,863,000, with the investment starting in 2023 and a construction duration of 3 years. The share of investments is divided as 20% in the first year, 40% in the second year, and 40% in the third year. The economic lifetime of the project is set to 30 years. The escalation base year is 2022, with an escalation rate of 2% per year. The yearly variable costs rate is set at 3%, and the insurance rate is 0.5%. The depreciation rate is 3.33%, and the decommissioning rate is 8%.

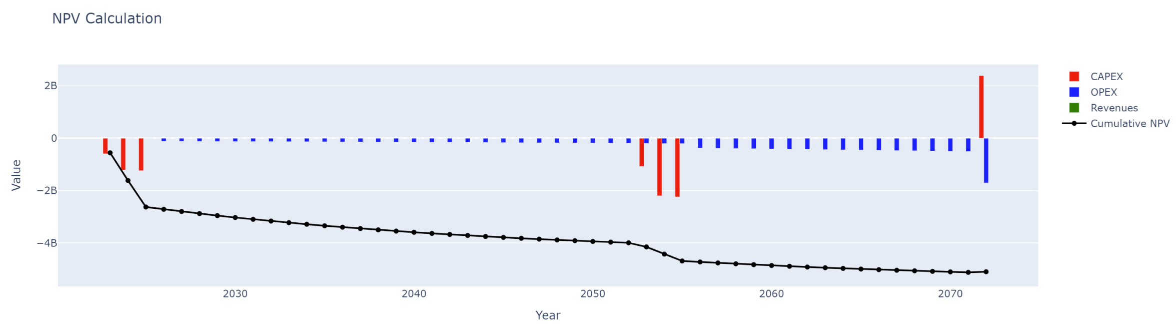


Figure 3.9: Cashflow modeling: NPV over time, no revenue model

3.3.3. Updated Model Method

The updated model method incorporates revenue generation, which is integrated into the financial analysis through flow of mass modeling. This method adds an important revenue component to the project by modeling the generation, transmission, and use of energy, as outlined earlier.

In this updated method, the FCF is calculated by considering CAPEX, OPEX, revenue, and taxes over the lifetime of the project. Revenue is generated from the sale of energy or resources produced by the system. Taxes are deducted from the revenue based on the earnings before tax (EBT). EBT is determined by subtracting depreciation and interest from EBITDA. Since financing and funding are not yet part of the model, interest is assumed to be 0%, and the EBT is essentially EBITDA minus depreciation.

The updated formula for free cash flow is:

$$FCF = \text{CAPEX} + \text{OPEX} + \text{Revenue} - \text{TAX}$$

where taxes are calculated as:

$$TAX = \text{Tax Rate} \times \text{EBT}$$

and

$$EBT = \text{EBITDA} - \text{Depreciation} - \text{Interest}$$

Since interest is assumed 0%, this simplifies to:

$$EBT = \text{EBITDA} - \text{Depreciation}$$

The second update to the model is reflected in the revised graphical outputs. Previously, the graphs only included a title and displayed the FCF over time alongside the NPV. Given the importance placed on transparency, the updated graphs now also convey the underlying assumptions of the analysis.

The revised layout features a headline indicating the system title, followed by a subtitle that lists the system's main components along with their respective levels of detail, referenced using their cost coding identifiers. Additionally, the graphs now present key financial assumptions, including the base year, escalation rate, WACC, project lifetime, and other critical parameters such as electricity price. This enhancement ensures that both structural and financial contexts are clearly communicated to the viewer.

Figure 3.10 shows the timeline of the same 50-year project as in figure 3.9 but this time revenues are added. The NPV accumulates over time and increases due to revenues.

This updated method allows for a more complete and transparent financial assessment by accounting for both the costs and the revenue streams of the project, as well as considering the impact of taxes and depreciation on the cash flows, and communicating key financial assumptions through graphical output

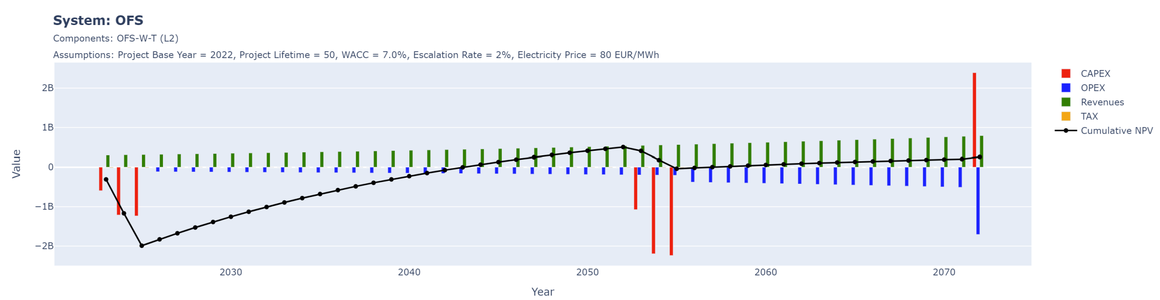


Figure 3.10: Cashflow modeling: NPV over time, revenue model

3.4. Uncertainty Modeling and Sensitivity Analysis

Uncertainty is an inherent aspect of offshore projects, as multiple factors influence financial feasibility and performance over time. To account for this variability, Monte Carlo simulations are used to sample from probability distributions representing the uncertainty of key parameters such as costs, revenues, escalation rates, and wind energy output. These simulations are performed at both the component level, where individual elements such as turbine efficiency and maintenance costs are assessed and at the system level, where the combined impact of uncertainties on overall project feasibility is evaluated. The probability distributions assigned to these variables are based on available data and expert assessments of their reliability. By running these uncertain values through the model, a distribution of key performance indicators such as NPV and IRR is obtained.

3.4.1. Types of Uncertainty and Input Modeling

A key consideration in uncertainty modeling is the type of uncertainty being analyzed. Technical uncertainty arises from variations in turbine performance, degradation rates, and unexpected downtime, all of which impact power generation and maintenance needs (Dao et al., 2020, Scheu et al., 2017). Economic uncertainty includes fluctuations in capital and operational expenditures, escalation rates, and future energy prices, all of which influence long-term project viability. Regulatory uncertainty stems from potential changes in tax structures, subsidies, or environmental policies that could affect financial projections (Sun and Sun, 2021). Market uncertainty includes variations in electricity demand, transmission constraints, and price volatility, which directly impact project revenues (Mora et al., 2019).

To accurately represent these uncertainties, appropriate probability distributions must be assigned to each variable. Normal distributions are used for parameters with natural variations around a mean, such as maintenance costs and operational efficiency. Lognormal distributions are applied to variables with asymmetric uncertainty, such as future energy prices or installation costs. Triangular distributions are used when expert judgment provides a minimum, maximum, and most likely estimate, often applied to factors like escalation rates and downtime probabilities (Barahmand and Eikeland, 2022, Le et al., 2024).

3.4.2. Monte Carlo Sampling

Monte Carlo simulation is a widely used approach for propagating uncertainty in techno-economic models, especially when input parameters are known to follow particular probability distributions identified through empirical data or literature review.

In this approach, uncertain model inputs, such as capital costs, operating expenses, energy demand, or escalation rates, are assigned statistical distributions. These may be parametric (e.g., Normal, Lognormal, Beta, Triangular) based on studies or industry guidelines. The simulation process then involves generating a large number of random samples from each input distribution and computing the resulting model outputs to derive a distribution of outcomes such as NPV or LCOE.

The simulation process consists of the following:

1. Distribution Definition: For each uncertain input, an appropriate distribution is selected.
2. Random Sampling: For each Monte Carlo iteration, a random draw is taken from every distribution.
3. Model Evaluation: The sampled values are passed into the financial model (e.g., NPV calculation), and the output is recorded.
4. Iteration: This process is repeated N times (typically 10^3–10^6), yielding a probability distribution of the output metric.

This probabilistic framework allows decision-makers to move beyond deterministic point estimates and incorporate uncertainty into project evaluations, reflecting the inherent variability in offshore infrastructure projects and energy markets.

3.4.3. Copula-Based Dependence Modeling and Sampling Framework

Since not all variables are independent, correlations between uncertainties must also be considered. For example, escalation rates for CAPEX and OPEX are often linked, meaning that an increase in one is likely to be reflected in the other. Similarly, fluctuations in energy prices may be correlated with macroeconomic conditions that also influence interest rates and financing costs. To capture these dependencies, copula-based modeling techniques can be applied. This ensures that Monte Carlo simulations reflect realistic interactions between financial and technical uncertainties, leading to more reliable system performance predictions.

To model the dependencies between two correlated time series or random variables (e.g., energy market prices), copula-based methods offer a powerful and flexible statistical framework. Copulas allow the joint distribution to be modeled separately from the marginal distributions, which is especially useful when dealing with non-normal marginals or tail dependence patterns (Frikha and Lemaire, 2013; Patton, 2012).

Step 1: Transforming Margins to Uniform Scale

The process begins by transforming each variable's marginal distribution to the unit interval $[0, 1]$ using their respective empirical cumulative distribution functions (CDFs). For a given variable X, this transformation is done via:

$$u = F_{\text{empirical}}(X)$$

This results in pseudo-observations (u, v) that are uniformly distributed and suitable for copula fitting.

Step 2: Selection and Estimation of Copula Family

Various copula families such as Clayton, Gumbel, Frank, and Joe can be used to capture different dependency structures, including asymmetric tail dependence. For each family, parameters are estimated via maximum likelihood estimation (MLE) using the transformed data.

Model selection is based on statistical criteria such as log-likelihood and AIC. The copula that yields the best goodness-of-fit is selected for further use. For example, a Joe copula with a specific parameter may provide the best representation of upper tail dependence.

Step 3: Conditional Sampling via the Inverse h-Function

To generate conditional samples, i.e., to simulate one variable conditional on a known value of the other, the conditional distribution derived from the copula is used. This is performed through the copula's h-function, which describes the conditional CDF of one variable given the other.

The conditional sampling procedure consists of multiple elements. Firstly a fixed value of the conditioning variable is transformed to copula scale using its empirical CDF. Next a sample of uniform random values is drawn from $U(0, 1)$. Then the conditional inverse h-function of the copula is applied to generate the conditional distribution. Finally the resulting conditional samples in copula scale are back-transformed to the original scale using the empirical quantile function. This enables realistic generation of dependent samples, which is valuable for scenario analysis or stochastic simulations.

Scenario Generation with Copula Sampling

Once the copula is fitted, it can be used to generate realistic scenarios over a desired time horizon. For instance, monthly samples can be drawn for each year of a multi-decade project, with each year containing twelve samples (one per month). The samples are aggregated annually, and used to feed cash flow models or valuation frameworks such as NPV analysis.

Three typical approaches to scenario generation using copulas include:

- Unconditional Sampling: Both variables are sampled directly from the joint copula, maintaining the estimated dependency without any additional forecasting constraints.
- Conditional Sampling (A given B): A forecast is defined for one variable (e.g., from an external model), and the other variable is sampled conditionally using the copula.

This framework supports comprehensive Monte Carlo simulations, allowing the propagation of dependency risk through to final financial indicators such as project NPV.

A crucial output of this analysis is the identification of the factors that have the greatest impact on system feasibility. Sensitivity analysis is used to determine which variables contribute most to financial risk, allowing decision-makers to prioritize mitigation strategies. By evaluating project performance under different scenarios, including best-case, worst-case, and expected-case conditions, it is possible to understand how robust the system is to external uncertainties. This approach provides valuable insights into risk management and supports the development of more resilient offshore wind projects.

3.5. Model Verification

Although model verification is not a direct component of the techno-economic analysis, it is essential to ensure that the developed model produces accurate and reliable results. This section outlines the verification procedures conducted to validate the correctness of both the cash flow modeling and the flow of mass modeling.

3.5.1. Model Tests

To verify the accuracy of our model, several test cases are implemented. These tests focus on cash flow calculations and system capacity validation.

Validation of Cash Flow Modeling

The financial model is verified by comparing its outputs against a reference MTBS model. A fictitious system is set up, incorporating multiple elements with reinvestments, divestments, decommissioning, and revenue generation. To ensure consistency, financial assumptions such as WACC, escalation rates, depreciation start (end of construction period), tax rates on revenue, and OPEX/CAPEX values are kept identical in both models.

The primary validation method involves calculating the cumulative NPV at the end of the project. If the NPV obtained from the developed model matches the NPV calculated in the Excel-based reference model, the cash flow model is considered verified.

To further validate cash flow projections, Python-based tests are implemented:

- Cash Flow Consistency Test: This test checks whether known OPEX and CAPEX values align with the outputs generated by the developed model. The test ensures correct calculations of escalated CAPEX, escalated OPEX, escalated revenue, and tax computations by comparing the expected and calculated values for each project year.
- Cumulative NPV Test: A separate test ensures that the cumulative NPV at the end of the project duration matches the reference model's NPV calculation, confirming the correctness of financial projections.

Validation of Flow of Mass Modeling

To verify the correct modeling of system capacity, a test is designed to check whether the modeled capacity aligns with predefined system constraints. A fictitious system is constructed using 'AND' and 'OR' gate logic to ensure correct capacity aggregation over time.

The verification process follows these steps:

- A system with known capacities is defined, including series and parallel configurations of elements.
- The capacity calculation model is run, tracking installed capacity over time.
- The computed capacity values are compared against the expected capacity inputs to confirm alignment.

If the installed capacity output from the model matches the predefined capacity values for all test years, the mass flow model is deemed accurate. These validation tests provide assurance that the implemented framework correctly represents both financial and physical system behaviors.

3.5.2. Model Verification Based on a Fictive System

In appendix B a fictive system is setup and both the cashflow modeling and flow of mass modeling are tested. The results show that the modeling is done correctly.

4 Research Methods

This chapter presents the methodology used to evaluate the techno-economic feasibility of multi-functional offshore islands by integrating port functionalities into offshore energy islands. The approach follows a structured framework that builds upon existing techno-economic assessment methods, adapting them to the context of multi-functional offshore islands.

4.1. Base Case: Offshore Energy System

The methodology begins by defining a base case scenario in which the offshore island is exclusively designed for energy-related functions. This involves specifying key system parameters, including generation capacity, storage functions, and essential infrastructure components. Additionally, the classification of supply chain elements, such as wind turbines, cables, transformers, and hydrogen storage, is standardized to ensure consistency in the analysis.

To establish a reference for evaluating potential enhancements, a benchmark LCOE is calculated. This follows the methodology outlined in Chapter 3, which includes supply chain inventarisation, process modeling using the concept of mass flow, and project cash flow modeling.

For the base case, the LCOE is determined by the cost contributions of components required to generate, store, transport, and integrate offshore energy into the mainland grid. Figure 4.1 illustrates this base case system, with the elements contributing to the LCOE indicated within the accolade.

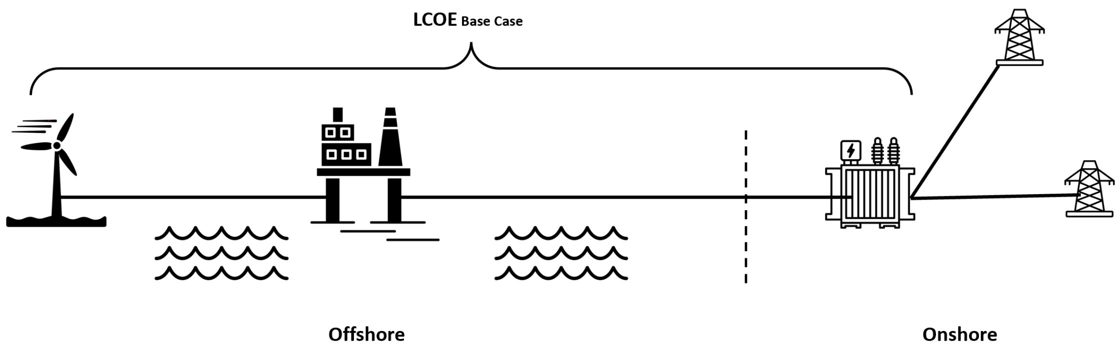


Figure 4.1: Offshore Energy System – LCOE Benchmark for a Single-Use Island

4.1.1. Levelized Cost of Energy

Utilizing the LCOE instead of the NPV is advantageous because LCOE does not require revenue assumptions to evaluate the financial feasibility of the system. The calculated LCOE value can be compared with values from the literature for other energy systems, providing an indication of whether the base case system is a competitive energy supply option for the mainland grid.

Using NPV, on the other hand, requires assuming a specific revenue stream. One possible approach would be to estimate revenue based on the current LCOE of the mainland grid multiplied by the system's output to determine yearly earnings. While this method could work, it is not preferred, as it would introduce an assumption about the LCOE in advance.

The LCOE is calculated as follows:

$$\text{LCOE} = \frac{\sum_{t=0}^{n} \frac{C_t + O_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}} \tag{4.1}$$

where:

- C_t = capital expenditures (CAPEX) in year t
- O_t = operational and maintenance costs in year t
- E_t = energy produced in year t
- r = discount rate / WACC
- n = project lifetime

This formulation ensures a standardized financial assessment of the offshore energy system without requiring revenue projections.

4.1.2. Produced Energy

While the installed generation capacity of an offshore energy system provides an upper bound on potential energy production, the actual output is typically lower due to various efficiency losses and external constraints. The real energy output of the system (E_t) is influenced by factors such as capacity factor, curtailment, and system availability.

Capacity Factor

The capacity factor (CF) is a key metric that quantifies the efficiency of an energy system by comparing its actual output over a period to its maximum possible output:

$$CF = \frac{\sum_{t=0}^{n} E_t}{n \times P_{rated} \times 8760} \tag{4.2}$$

where:

- P_{rated} = installed (rated) generation capacity (MW)
- E_t = actual energy produced in year t (MWh)
- n = number of years in the project lifetime
- 8760 = total hours in a year

For offshore wind farms, typical capacity factors range from 40% to 55%, depending on wind conditions, turbine efficiency, and wake effects (Kucuksari et al., 2019, Carreno-Madinabeitia et al., 2021).

Curtailment Effects

Curtailment occurs when generated electricity cannot be injected into the grid due to system constraints, low demand, or overproduction from other renewable sources. With an increasing share of renewables in the energy mix, curtailment rates tend to rise unless additional storage or grid flexibility measures are implemented. The curtailed energy fraction (C_{frac}) can be estimated as (Bird et al., 2016):

$$C_{frac} = \frac{E_{curtailed}}{E_{potential}} \tag{4.3}$$

where:

- $E_{curtailed}$ = curtailed energy due to grid constraints (MWh)
- $E_{potential}$ = potential energy production without curtailment (MWh)

Projections for curtailment can be made using historical trends and scenario analyses of grid flexibility enhancements, such as demand-side management, energy storage, and interconnections.

Availability and Downtime

System availability is another crucial factor affecting real energy production. Planned maintenance, unexpected failures, and adverse weather conditions (e.g., extreme storms leading to shutdowns) contribute to downtime. The availability factor (A_f) is expressed as (Kikuchi and Ishihara, 2021):

$$A_f = 1 - \frac{T_{downtime}}{T_{total}} \tag{4.4}$$

where:

- $T_{downtime}$ = total downtime due to maintenance or failures (hours)
- T_{total} = total operating hours in a given period (hours)

For offshore wind farms, availability factors generally range from 90% to 98%, with well-maintained systems reaching the upper end of this range.

Projected Trends in Renewable Energy Penetration

As the share of renewables increases in the energy mix, the frequency of curtailment events may rise due to the variability of wind and solar power. Studies indicate that with high renewable penetration (e.g., >50%), curtailment can reach significant levels unless mitigation strategies such as increased storage capacity or enhanced interconnections are implemented (Bird et al., 2016).

Effective Energy Output Calculation

Taking all these factors into account, the real annual energy output of the offshore energy system can be estimated as (Schallenberg-Rodriguez, 2013b):

$$E_t = P_{rated} \times 8760 \times CF \times A_f \times (1 - C_{frac}) \tag{4.5}$$

This formula ensures that realistic energy production estimates are used in LCOE calculations, providing a robust assessment of the financial viability of the offshore energy system.

4.2. Selection of Port and Logistics Functions

To explore multi-functionality, additional port and logistics functions with regional significance are identified and evaluated. MCDA is used to determine the most viable function for integration, considering economic, logistical, and technical factors.

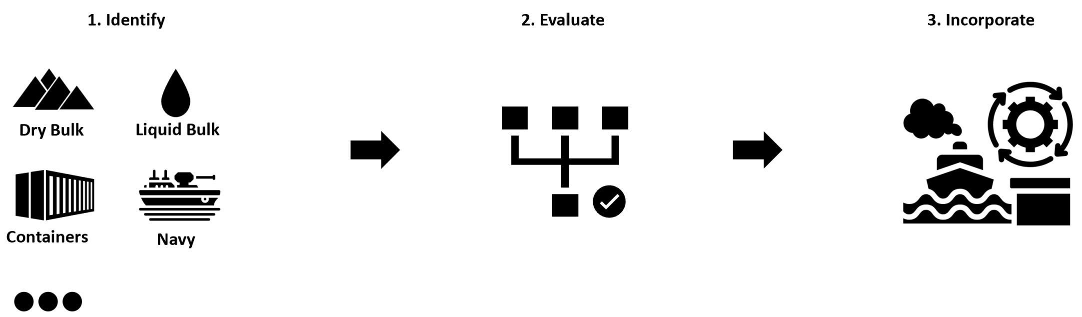


Figure 4.2: Identification and Selection Process of Port Functionalities

The first step in applying MCDA involves identifying all feasible port functions that can be implemented on an offshore island.

4.2.1. Identification of Potential Functions

Offshore energy islands can support a wide range of functions, primarily categorized into port and energy-related activities. Port functionalities may include container handling, transshipment, roll-on/roll-off (RORO) operations, and facilities for both dry and liquid bulk cargo. They can also serve passenger transport, ship bunkering, and host maintenance and repair operations for vessels. Additional roles could involve acting as an offshore service base for wind farm operations and maintenance, supporting fisheries and seafood processing, and offering cold storage and logistics services.

Energy-related functions include the integration of industrial zones for maritime and energy industries, floating storage and regasification units for LNG, and terminals dedicated to hydrogen export and import. The functions related to the case will be identified through a combination of literature review and expert consultation to ensure a comprehensive evaluation of potential opportunities and operational constraints.

4.2.2. MCDA Methodology

To guide the selection of optimal functionalities, a MCDA framework is applied. This approach enables structured and transparent evaluation by aligning functional options with strategic objectives such as energy security, logistics efficiency, and environmental sustainability. The process also accounts for practical constraints like spatial limitations, regulatory frameworks, and economic viability.

Evaluation criteria span several dimensions, including economic (e.g., investment and operational costs, revenue potential), technical (e.g., infrastructure complexity, technology readiness), environmental (e.g., carbon footprint, impact on marine ecosystems), logistical (e.g., supply chain efficiency, integration with existing networks), and regulatory or social aspects (e.g., policy alignment, stakeholder acceptance). Weights are assigned using expert judgment, and a Weighted Sum Model is used to rank alternatives (Guitouni and Martel, 1998).

4.3. Base Case: Port System

Two base cases are established by modeling the selected port functionality as a standalone onshore and offshore operation. This process involves inventorying supply chain components specific to the port system, estimating capital and operational expenditures, and calculating its NPV as a benchmark for financial feasibility.

4.3.1. Ring-Fencing and Greenfield Assumption

To ensure a standardized evaluation, a ring-fenced approach is applied by assuming a greenfield project. This means that, for the purpose of establishing the base cases, the costs, NPV, and feasibility of a newly developed port functionality are assessed as if built from scratch. While in reality, this function may already exist within the port, this assumption allows for an objective evaluation of its standalone financial viability. The feasibility assessment follows the techno-economic analysis process outlined in Chapter 3.

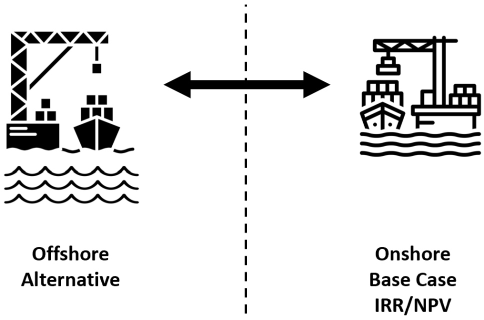


Figure 4.3: Greenfield Port Function Base Case Benchmark

4.3.2. Net Present Value

For the financial assessment of the base cases of the port function, the NPV method is employed, requiring revenue assumptions. The sizing of capacity can be determined through market studies or by referencing the current scale of similar port functions. Revenue estimations leverage MTBS expertise, ensuring realistic financial projections. Unlike the LCOE, an equivalent LCOX for goods handled in the port function is not practical, as only a small portion of its supply chain is considered in the evaluation.

4.3.3. Capacity Measurement and Energy Use

The energy demand of the port function is estimated by inventorying consumption across various components, including machinery and operational facilities. The total energy demand serves as a baseline for evaluating future energy consumption when the port is integrated with the offshore island.

The capacity of the port system is defined in terms of container handling capacity, cargo volume, and vessel throughput. To ensure alignment with the offshore port system, the operational requirements of the onshore base case, including required infrastructure, are assessed. This alignment ensures that the capacity of the onshore port is comparable to the offshore island port function in terms of throughput.

4.4. Combined System Setup

In this phase, the selected port function is integrated into the offshore island, transforming the system by incorporating new supply chain elements and identifying potential synergies. These synergies may include reduced energy transmission costs due to on-island energy consumption or lower dredging requirements.

The island's design is updated to accommodate port functions, transitioning from an energy transshipment hub to a multi-functional facility supporting both energy transshipment and usage. Additional elements, such as a hinterland pipeline for liquid bulk, are incorporated to facilitate port operations. Conversely, some elements are streamlined, such as reduced dredging.

The integration of both functions can lead to mutual benefits: energy consumption by the port reduces the need for additional cable capacity, economies of scale can be realized in the island's design, and the optimized use of space on the island enhances overall efficiency.

The system is redesigned, and potential benefits are inventoried through a partial techno-economic analysis, including mass flow, capacity, and energy modeling, followed by comprehensive checks.

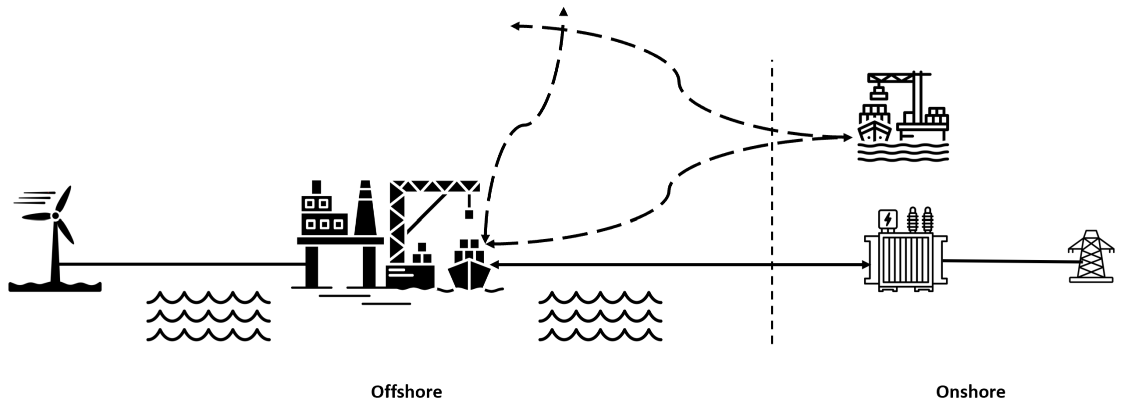


Figure 4.4: Integrated System: Multifunctional Offshore Island

4.5. Evaluation of Multifunctional System

The financial evaluation is carried out by dividing the island into two distinct components, energy and port system, allowing for the separate recalculation of LCOE and NPV for each. This approach enables a structured comparison between the base case and the multi-functional island, ensuring the financial feasibility is assessed consistently.

The full techno-economic analysis process is applied, encompassing supply chain modeling, mass flow analysis, capacity assessment, cash flow modeling, and market/revenue/energy production scenarios. Extensive sensitivity analysis is conducted on financial parameters to evaluate the robustness of the financial feasibility.

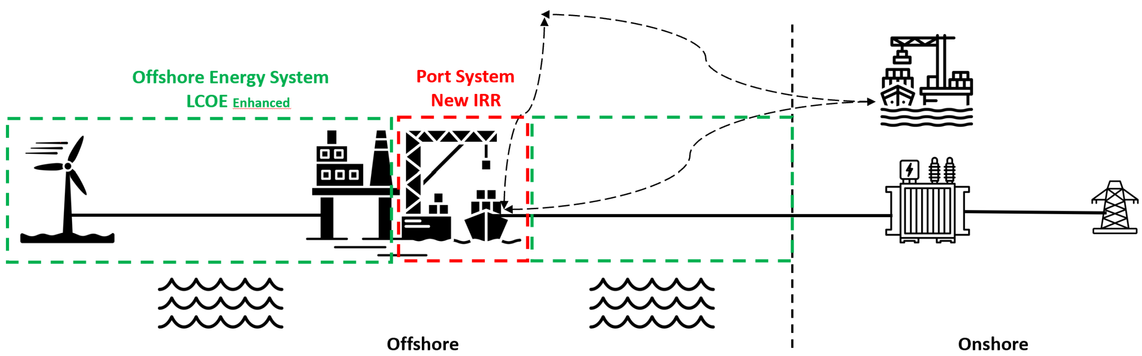


Figure 4.5: Evaluation of Divided Systems, and Comparison to Benchmark

4.6. Case Study

The previously described methodology is applied to the case of the Princess Elisabeth Island. The objective of this case study is to evaluate the potential financial benefits of incorporating multi-functionality into the current design of the island. Additional functionalities will be identified based on the needs and operations of the nearby Port of Bruges, ensuring relevance to regional logistical and economic contexts. By following the structured framework, this application serves as a valuable reference for future studies where the same assessment method can be employed. The case aims to provide insights into the extent to which multi-functionality may enhance the financial feasibility of offshore energy islands.

5
Case: Princess Elisabeth Island

The focus of this case is on integrating the offshore wind system with an additional port functionality from the nearby Port of Bruges. This integration aims to assess whether improved financial feasibility can be achieved for both components. By following the process outlined in Chapter 4, the objective is to determine whether this integration can lead to enhanced financial outcomes for both elements.

Introduction Princess Elisabeth Zone

The Princess Elisabeth Zone (PEZ) project is a development in offshore energy infrastructure, aimed at integrating renewable energy generation with transmission capabilities in the North Sea. At the core of the project is the construction of an artificial island that will house both AC and HVDC substations, enabling the connection of offshore wind farms to the onshore grid. The project is designed to deliver a total transmission capacity of up to 3.5 GW, with phases planned as follows: 700 MW (AC) in Phase 1, 1,400 MW (AC) in Phase 2, and 1,400 MW (HVDC) in Phase 3 (Elia, 2022, Goethals et al., 2023).

Part of the broader Modular Offshore Grid (MOG2) initiative, the PEZ will enhance the scalability and flexibility of offshore energy transmission systems, supporting Europe's renewable energy transition. The project will facilitate the export of renewable energy from offshore wind farms and provide provisions for future interconnections with countries like the United Kingdom and Denmark. With a construction timeline from 2024 to 2030, the PEZ aims to contribute to energy security, sustainability, and the achievement of Europe's carbon reduction goals (FPS Economy, 2024, Valerio et al., 2025).

Introduction Port of Bruges

The Port of Bruges, located along the Belgian coast, is a major European maritime gateway, supporting a wide range of activities including container handling, bulk goods, and industrial services. Spanning approximately 3,000 hectares, the port offers a range of terminals and deep-water access, accommodating both seagoing and inland vessels. In 2022, the port handled over 10 million tons of cargo and processed more than 2.1 million TEUs in containers (Port of Antwerp Bruges, 2025).

A notable feature of the Port of Bruges is the Zeebrugge gas hub, one of Europe's key energy infrastructure facilities. Zeebrugge serves as a critical entry point for liquefied natural gas (LNG) and plays a role in Europe's gas supply chain. The hub has a capacity to import up to 9 billion cubic meters of LNG annually, making it one of the larger LNG import terminals in Europe. This strategic location enables the storage, distribution, and re-exportation of LNG, further enhancing the port's role in the energy sector (Fluxys, 2024b).

The Port of Bruges also supports industries such as chemicals, automotive, and foodstuffs, alongside being a key logistics center for Europe, with efficient connectivity to road, rail, and inland waterways. It remains a vital node in Belgium's industrial network, supporting sustainable trade and energy security across the region (Port of Antwerp Bruges, 2025).

5.1. Base Case: Offshore Energy System

The first base case concerns the stand-alone offshore wind energy system. A TE analysis is conducted to establish a benchmark LCOE. This benchmark will later serve as a reference for comparison with the offshore wind energy system integrated into the multi-functional island scenario.

5.1.1. System Elements and Components

The offshore wind energy system includes the MOG2 project, which comprises electricity transmission elements, the island, Ventilus and Boucle de Hainaut, which are onshore connections and it also includes the wind farms, consisting of turbines, foundations, and inter-array cables (FPS Economy, 2024).

The artificial island, visualized in figure C.1 in appendix C, serves as the central hub for both AC and HVDC substations. It enables the connection of offshore wind farms and the export of electricity to the mainland. The island is constructed using a caisson-based approach, with a footprint of approximately 25 hectares on the seabed and a usable area of 6 hectares. The core of the island is filled with sand, providing a stable foundation for the required infrastructure (Goethals et al., 2023).

The timeline visualized in figure C.2 in appendix C, outlines the phased development of the Princess Elisabeth Zoned offshore wind project, spanning from 2024 to 2030. It is organized into three tenders, each comprising multiple interconnected projects.

Tender 1 focuses on a 700 MW capacity, with permitting for Ventilus and the First Wind Farm tender beginning in 2024. Construction follows in 2025 and continues into 2026, including MOG2 Phase 1. Tender 2 increases capacity to 1400 MW, starting with Boucle du Hainaut permitting in early 2026, followed by the Second Wind Farm tender and MOG2 Phase 2 construction, progressing through 2027. Tender 3 completes the project with another 1400 MW, including the Third Wind Farm tender and MOG2 Phase 3 construction, concluding by 2030 (FPS Economy, 2024).

Transmission Infrastructure

The offshore high-voltage AC and low-voltage equipment have a total capacity of 2.1 GW. These include 220/66/66kV transformers, 220kV shunt reactors, 220kV and 66kV GIS switchgear, and low-voltage protection systems. Additionally, an HVDC converter station with a capacity of 1400 MW at 525 kV is installed on the island to facilitate long-distance transmission (Elia, 2023, Valerio et al., 2025).

The energy transmission system comprises multiple cable networks. The AC export cables consist of 330 km of 220kV three-phase AC cables connecting Princess Elisabeth Island to the mainland. The HVDC export system includes 55 km of 525kV monopolar HVDC cables linking the island to the onshore connection point. The project also includes provisions for future interconnections with the United Kingdom and Denmark via additional HVDC cable systems, although these are beyond the current scope (Elia, 2023).

Onshore, the system includes additional infrastructure to ensure smooth integration with the existing power grid. The onshore AC transmission network consists of 220kV three-phase AC cables connecting the landing point to the Ventilus connection hub. Similarly, the onshore HVDC system features a 1400 MW, 525kV HVDC converter station in a bipole configuration. The necessary high-voltage and low-voltage AC equipment, rated at 2.1 GW, is integrated into the Ventilus infrastructure (Elia, 2023, Valerio et al., 2025).

Offshore Windfarms

The offshore wind farms connected to the system have a total capacity of 3.5 GW, with installations occurring in line with the MOG2 phases. The connection of wind farms occurs at the 66kV level, which falls under the responsibility of wind farm developers. The offshore wind farm includes approximately 650 kilometers of 66 kV inter-array cables to connect the turbines to the offshore substations (Febeliec, 2025).

Artificial Island

Furthermore, the construction of the artificial island requires approximately 2.8 million cubic meters of sand for land reclamation. The island's structure is reinforced with concrete caisson elements, which provide durability and protection against erosion. To support operational activities, the island is equipped with facilities such as mooring stations for crew transfer vessels and supply vessels, refueling and bunkering infrastructure, storage areas, accommodation and control rooms, a helipad, and internal road networks (Boerema et al., 2023, Linaraki et al., 2023). Figure C.3 in appendix C shows physical characteristics of the Artificial Island.

Figure 5.1 shows key elements of the offshore wind supply chain of the Princess Elisabeth zone.

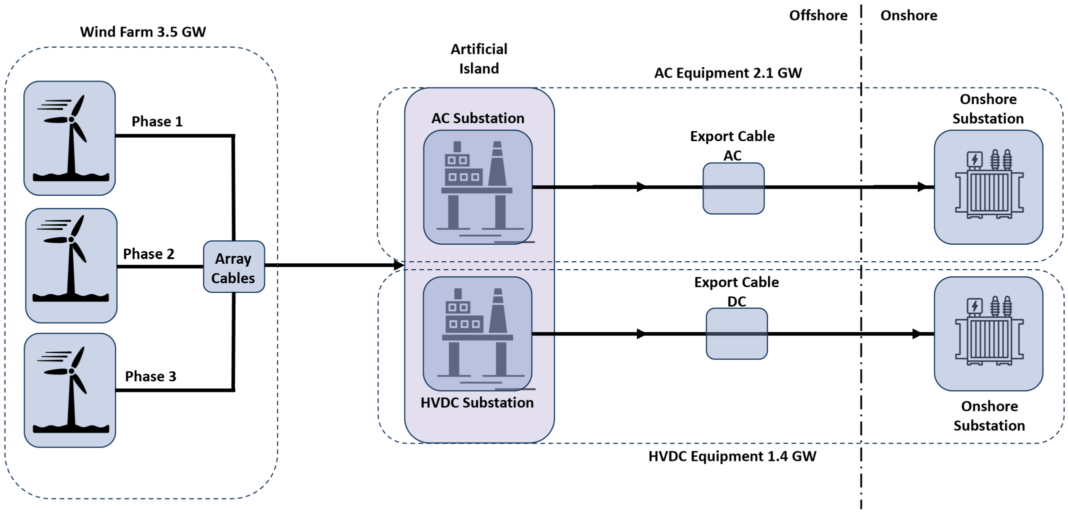


Figure 5.1: PEZ zone Elements Overview

The table C.1 in appendix C provides an overview of all elements in the PEZ supply chain along with their characteristics. Cost data is derived from reports by Febeliec, 2025 and PWC, 2023. In appendix C, figure C.4 gives an overview of the locations of the elements of the PEZ system.

Figure 5.2 illustrates the cost distribution of various elements of the PEZ.

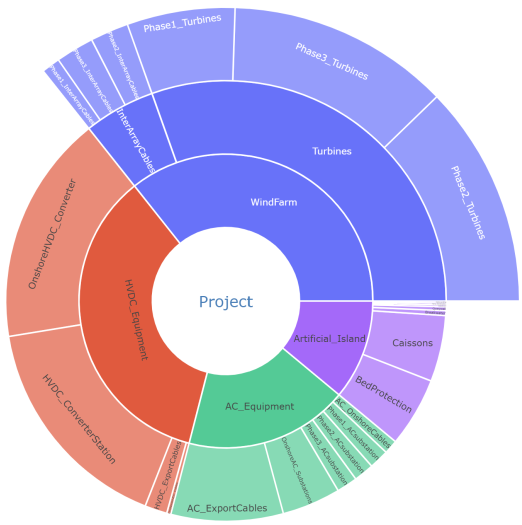


Figure 5.2: Sunburst Plot of PEZ Cost Distribution

A major portion of the cost originates from the HVDC infrastructure, despite only 40% of the total capacity utilizing it. HVDC is typically used for long-distance transmission to minimize losses; however, in this case, the distance is only 40 km. Additionally, while the cost of the artificial island is relatively small compared to the overall system, it remains a significant expenditure. The majority of the investment comes from wind farms, which is reasonable given that more than 350 wind turbines are planned for installation (Y. Zhang et al., 2016, Febeliec, 2025).

5.1.2. Evaluation Base Case LCOE

The base case is evaluated based on the LCOE metric. First, the cash flow is determined under specific financial assumptions. Next, the yearly energy output is calculated. These calculations allow for the determination of the LCOE value.

Free Cash Flow

The financial assumptions for the elements are outlined in Table C.1 in Appendix C. The methods used to define the free cash flow and NPV align with those described in Chapter 3. For the overall system, the WACC is set at 7%, the base year is 2022, and the project lifetime is assumed to be 60 years. For the NPV revenue is also modeled under the assumption that the price of electricity is 80 EUR/MWh and the tax rate at 20% (Meinke-Hubeny et al., 2017, Belgian Energy Market, 2025).

Figure 5.3 shows the free cash flow of the PEZ base case over time.

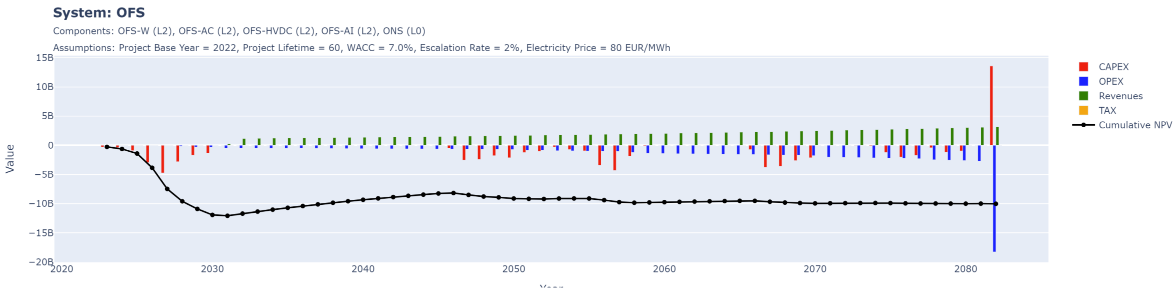


Figure 5.3: Overview of PEZ Base Case FCF

Yearly Energy Output [MWh]

Figure 5.4 shows the available capacity in MW of the PEZ base case over time, which is found using the flow of mass method described in chapter 3.

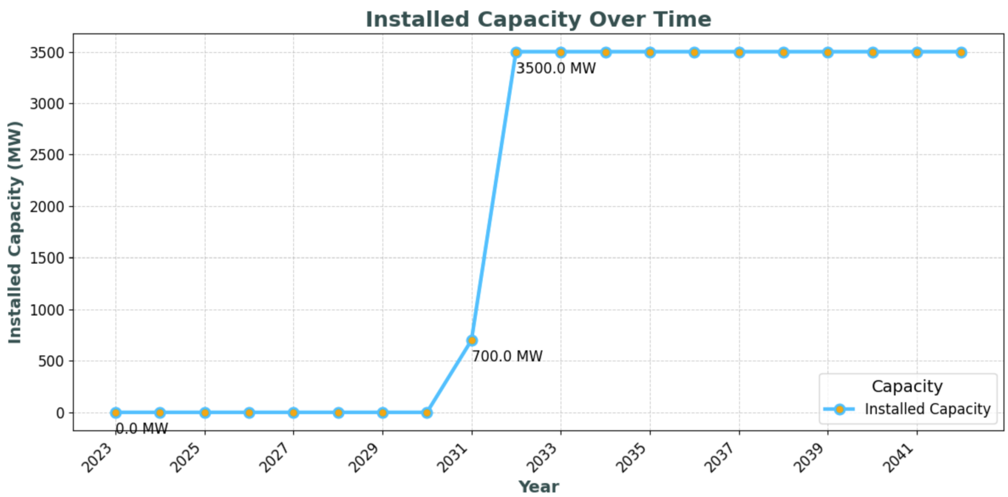


Figure 5.4: Overview of PEZ Base Case Capacity

The following assumptions were applied in the calculation of the yearly energy output [MWh]. These values align with those used in the report by Febeliec, with the goal of obtaining a result comparable to theirs:

Parameter	Value
Installed Capacity (cap)	0 - 3500 MW
Curtailment ($1-\eta$)	97% utilization (3% curtailment)
Operational Capacity Factor (CF)	41%
Downtime (dT)	10 days per year

Table 5.1: Key assumptions used in the Energy output calculation (Febeliec, 2025)

The annual energy production is calculated as (Schallenberg-Rodriguez, 2013a):

$$E_t = cap \times (1-\eta) \times \left(365 \times 24 \times CF \times \left(1 - \frac{dT}{8760}\right)\right) \tag{5.1}$$

LCOE

Finally, both energy output and free cash flows are discounted at 7% annually, resulting in an LCOE of 224 € /MWh. At the beginning of 2025, Febeliec, the federation representing Belgian industrial energy consumers, published a report analyzing the cost increases of the PEZ and their impact on LCOE. In this report, a revised LCOE calculation was presented for the PEZ and estimated as 202 EUR/MWh (Andreas, 2025).

While this study incorporates all financial assumptions from the Febeliec report, it arrives at a different LCOE value. The discrepancy arises from the way energy output is calculated. The Febeliec report does not explicitly address the yearly energy output of the system, which significantly affects the final LCOE estimate. By reverse-engineering their approach, it becomes evident that Febeliec's calculation assumes full operational capacity by 2030, a timeline that does not align with the actual projected output of the system at that stage.

This case highlights the critical importance of standardization and transparency in LCOE studies. Furthermore, it demonstrates the practical value of the flow of mass concept, ensuring that realistic operational constraints are correctly accounted for in economic assessments. The final NPV value of the system is found to be -10.0 billion EUR, under the assumption of 80 € /MWh electricity wholesale price, which is the average value of 2024 and tax rate of 20% (Meinke-Hubeny et al., 2017, PwC, 2025, Belgian Energy Market, 2025).

The results for the base offshore wind energy system indicate a relatively high LCOE, raising concerns about the sustainability and attractiveness of the investment. The calculated LCOE of approximately 224 EUR/MWh is significantly above typical industry benchmark values. Such elevated LCOE values suggest that, under the assumed financial conditions, the standalone business case for offshore wind development would be financially challenging. For comparison, the *Cost of Wind Energy Review: 2024 Edition* by NREL reports an LCOE of approximately 120 EUR/MWh for fixed-bottom offshore wind, reflecting competitive costs achieved through stable turbine and transmission prices. However, the assumptions underlying this benchmark differ substantially from current European market realities. A key distinction lies in the cost breakdown: according to NREL, turbines represent approximately 50% of total CAPEX, while transmission and export infrastructure accounts for only 18%. In contrast, in the present case study, the capital cost structure derived from recent Elia auction results shows that transmission and export components comprise approximately 50% of total CAPEX. This disproportionate share of transmission costs is a major driver of the elevated LCOE. The reason for this deviation can be found in recent European market conditions. Febeliec, 2025 highlights that the Energy Island project in the Princess Elisabeth Zone has suffered from extreme cost overruns, particularly for the HVDC transmission infrastructure. Transmission-related costs, initially estimated at around 2 billion euros, have escalated to approximately 4 billion euros due to a combination of supply shortages, limited competition among HVDC suppliers, and the non-standard artificial island design, which increased technical complexity and costs.

Additionally, broader global factors have contributed to price surges. The rapid electrification efforts across Europe and beyond have created unprecedented demand for offshore grid infrastructure, while volatile commodity prices for key materials such as copper, steel, and rare earth elements have further strained supply chains (Riva Sanseverino and Luu, 2022). Elia attributes approximately half of the Energy Island's cost increase to these "market effects," meaning that procurement prices have risen independently of project-specific inefficiencies.

Overall, the high LCOE observed does not necessarily indicate inefficiency in offshore wind technology itself. Instead, it highlights the impact of structural market shortages, regional infrastructure cost inflation, and project-specific design decisions. This finding underscores the critical importance of controlling grid connection costs and optimizing infrastructure design when aiming to maintain offshore wind as a competitive renewable energy source.

5.1.3. Sensitivity Analysis LCOE

To evaluate the robustness of the LCOE, a sensitivity analysis was conducted focusing on two key uncertainties: the WACC and construction delays. The full methodological overview can be found in Appendix C.

WACC is examined through three scenarios: 5.5%, 8.5%, and 10%, representing a range of financial perspectives from societal to investor-based (Commission, 2021). Rather than modeling it probabilistically, WACC is treated as a scenario input to observe its influence on the LCOE outcomes.

Construction delays represent another important uncertainty, as they affect the timeline for system commissioning and, consequently, energy output. A Poisson distribution with a mean delay parameter of 3 is used to simulate delay scenarios (Muralidhar et al., 2018, Chidambaram et al., 2012), including the rare possibility of early completion . These delay values are incorporated into Monte Carlo simulations, generating 10,000 possible development paths for system capacity over time. Figure 5.5 illustrates the resulting capacity trajectories for the PEZ base case.

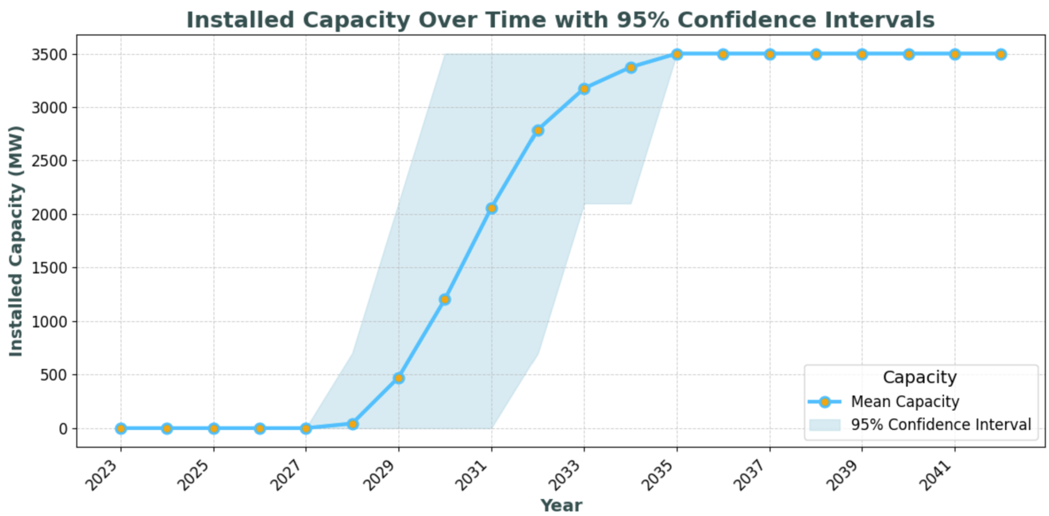


Figure 5.5: Simulated Capacity Trajectories for PEZ Base Case under Construction Delay Uncertainty

A total of 10,000 simulations were run, each combining randomly sampled delay scenarios for individual components with the defined WACC levels. For each simulation, the resulting LCOE was computed. While some simulations had similar average delays, their LCOE values varied due to the system's interdependent structure. In certain cases, delays in a single critical component disproportionately affected performance, leading to a wider range of outcomes.

The resulting LCOE distributions under different WACC scenarios are shown in Figure 5.6, highlighting the combined effect of financial and schedule-related uncertainties. The results show that under a WACC of 10%, the 95% confidence interval for the LCOE spans from approximately 200 to 260 EUR/MWh, demonstrating significant sensitivity. This variability underlines the need for robust risk management strategies to mitigate scheduling uncertainties, which have a material effect on the financial feasibility of offshore wind developments.

This is particularly relevant given the current investment climate. The 3.5 GW of offshore wind capacity must be delivered by private developers, yet investor appetite in the European offshore wind sector has cooled considerably (Reuters, 2025). If investor participation slows, the deployment of wind turbines could lag significantly, even as the expensive grid and transmission infrastructure is already being constructed. This mismatch could further erode the project's financial feasibility.

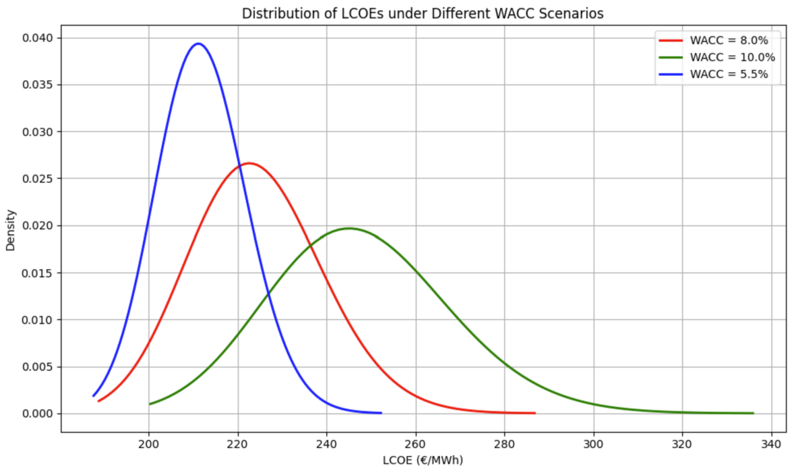


Figure 5.6: LCOE Distributions under Delay Uncertainty and WACC Scenarios

In projects involving significant reinvestments later in the project lifecycle, the LCOE can exhibit a local minimum at a specific discount rate. This phenomenon occurs due to the interaction between the time value of money and the project's cost structure.

At lower discount rates, the effect of future reinvestments on the LCOE is more pronounced, causing an increase in the LCOE. As the discount rate rises, the present value of future costs decreases, leading to a reduction in their impact on the overall LCOE. However, at higher discount rates, the discounting of future electricity generation becomes more significant, which in turn increases the LCOE again. This results in a U-shaped curve of LCOE as a function of the discount rate as illustrated in figure 5.7.

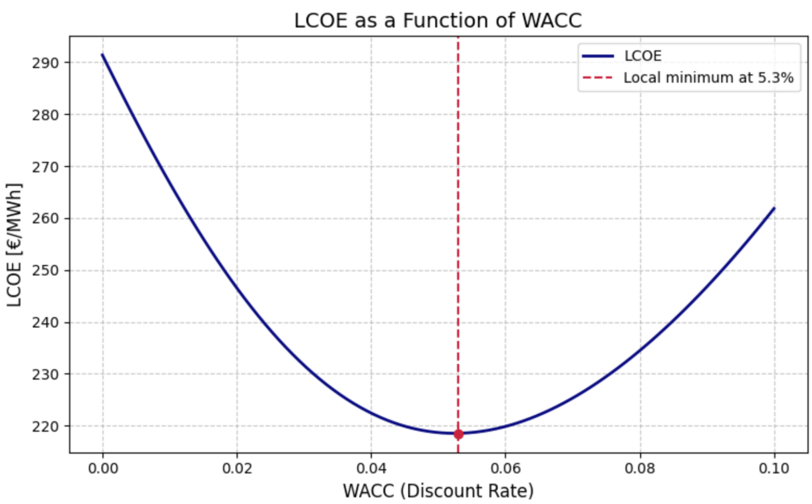


Figure 5.7: LCOE as a function of the WACC

For the base case, a local minimum in the LCOE occurs at a WACC of approximately 5.3%, representing an optimal balance between discounting future costs and generation.

Achieving a WACC of 5.3% for an offshore wind system is realistic under favorable financing and regulatory conditions. In mature offshore wind markets such as those in Northern Europe, projects often benefit from access to low-cost capital through public-private partnerships, export credit agencies, or concessional loans from institutions like the European Investment Bank. These mechanisms can significantly reduce financing costs, especially when combined with long-term revenue certainty through Contracts for Difference (CfDs) or corporate Power Purchase Agreements (PPAs). Under such circumstances, WACCs between 4.5% and 6% are commonly observed, making the assumed 5.3% well within reach for de-risked and efficiently structured projects (Commission, 2021).

However, the ability to secure such favorable terms depends heavily on the project's risk profile, regulatory framework, and broader macroeconomic conditions. Rising interest rates, inflation in the supply chain, and increasing exposure to merchant market risks can push WACCs higher, particularly for projects without stable offtake arrangements (Commission, 2021). As such, while a 5.3% WACC reflects an optimistic but attainable benchmark, project developers must incorporate sensitivity analyses and account for a potential range of financing scenarios to ensure financial robustness. It ultimately represents a best-case equilibrium between the cost of capital and the present value of future energy generation.

5.1.4. Base Case Enhanced

The current base case, as proposed by Elia, appears suboptimal. The inclusion of HVDC significantly raises costs, although it is not an essential design choice. HVDC systems are typically used to reduce transmission losses over long distances, but the PEZ is located only 40 km from the shore, which is relatively close and does not justify the high associated costs (Y. Zhang et al., 2016).

Two alternative design options are proposed to improve cost efficiency:

1. Replace the HVDC component with AC equipment of the same capacity.
2. Retain HVDC, but integrate the Nautilus and Triton interconnectors (connecting to the UK and Denmark (RUMES et al., 2022)), assessing the added value and potential revenue from this functionality.

AC Equipment Only

In the first alternative, the HVDC equipment is replaced with AC equipment, maintaining the same capacity and construction timeline as the original HVDC setup.

Figure 5.8 shows key elements of the offshore wind supply chain of the Princess Elisabeth zone for the case where only AC equipment is used.

In appendix C the system component table and the 2 cash flow related figures are given. The financial assumptions for the elements are outlined in Table C.2. Figure C.7 illustrates the FCF of the PEZ base case with only AC equipment over time, and figure C.8 provides a sunburst chart depicting the cost distribution across various components of the PEZ when only AC equipment is considered.

The LCOE for this case is calculated at €182/MWh, which reflects a 13% decrease compared to the base case with HVDC. The final NPV value of the system under the assumption of 80 € /MWh electricity wholesale price, which is the average value of 2024 and a tax rate of 20%, (Belgian Energy Market, 2025,PwC, 2025) is found to be -5.9 billion EUR.

Replacing HVDC with AC infrastructure leads to a substantial reduction in the overall project CAPEX and, consequently, a noticeable decrease in the LCOE to 182 EUR/MWh, bringing the project closer to competitive industry standards.

The preference for more cost-effective infrastructure choices is also strongly supported by Febeliec. In their 2024 position paper, Febeliec expresses concerns about the excessive cost escalation associated with the Energy Island project, largely attributed to the selection of HVDC technology for relatively short transmission distances. They argue that traditional AC systems could offer a more economically viable solution, particularly for projects where distance and power levels do not strictly require HVDC.

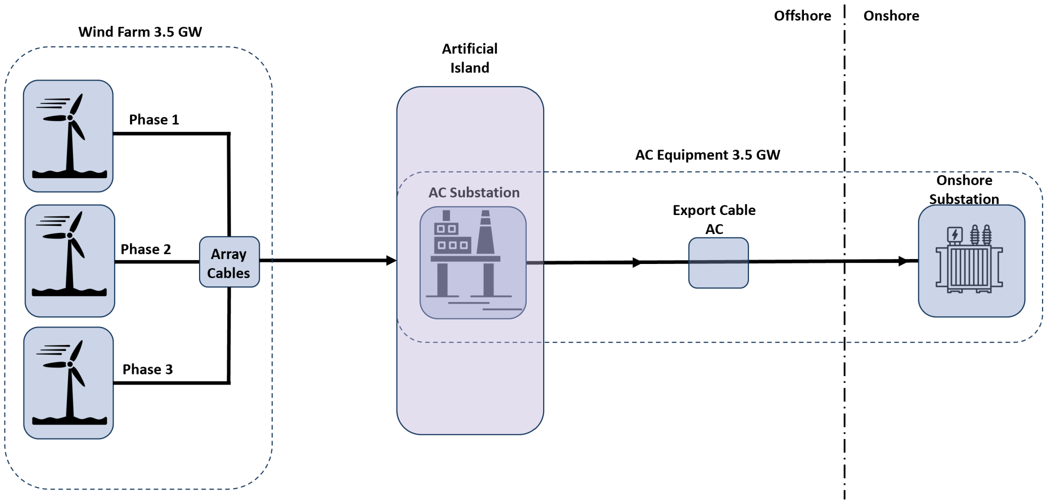


Figure 5.8: PEZ zone Elements Overview, Enhanced Base Case: AC only

According to Febeliec, the push towards HVDC infrastructure in the Belgian offshore development has led to a significant increase in grid connection costs, contributing to an overall offshore wind system cost exceeding 200 EUR/MWh.

Furthermore, Febeliec criticizes the lack of cost-benefit analysis supporting the choice for HVDC infrastructure, highlighting that the additional technical advantages of HVDC, such as reduced transmission losses over long distances, are less relevant in relatively proximate offshore developments like the PEZ. Their position emphasizes the need for rigorous economic justification when choosing more complex and expensive transmission technologies.

Thus, the substitution of HVDC with AC equipment in the enhanced base case is not only technically feasible but is also aligned with broader industry recommendations to prioritize economic efficiency, particularly in constrained markets facing rapid cost inflation.

HVDC as an Interconnector

The second enhanced base case incorporates the interconnector linking Belgium, the UK, and Denmark with a 1.4 GW capacity. Its primary purpose is to facilitate electricity arbitrage among the three countries, making the most of varying electricity prices (Bunn and Zachmann, 2010, Turvey, 2006). This section examines the financial benefits of the interconnector in terms of arbitrage opportunities and its impact on the LCOE.

Figure 5.9 shows key elements of the offshore wind supply chain of the Princess Elisabeth zone for the case where the interconnector is incorporated into the design.

The estimated length of HVDC cables required to connect the island to both Denmark and the UK is approximately 700 km, and using the cost per kilometer detailed in Table C.1, the total CAPEX for the cables is €2,835 million.

The interconnector could potentially enable up to 11.65 TWh/year of arbitrage transfers, generating up to €260.5 million/year in additional revenues. These revenues, in conjunction with the capital costs, will be incorporated into the free cash flow of the PEZ system, resulting in a revised LCOE.

The full calculation of the extra costs and additional revenue from the interconnector can be found in appendix C. Figure C.9 displays the free cash flow over time for the base case with the HVDC interconnector, and Figure C.10 shows the cost distribution of various components of the PEZ with the HVDC interconnector, both of which can also be found in appendix C.

The LCOE for this case, after accounting for the arbitrage revenue, is calculated at €237/MWh, showing a 5% increase compared to the base case with no HVDC interconnector. The final NPV value of the system under the assumption of 80 € /MWh electricity wholesale price, which is the average value of 2024 and a tax rate of 20%, (Belgian Energy Market, 2025, PwC, 2025) is found to be -11.4 billion EUR.

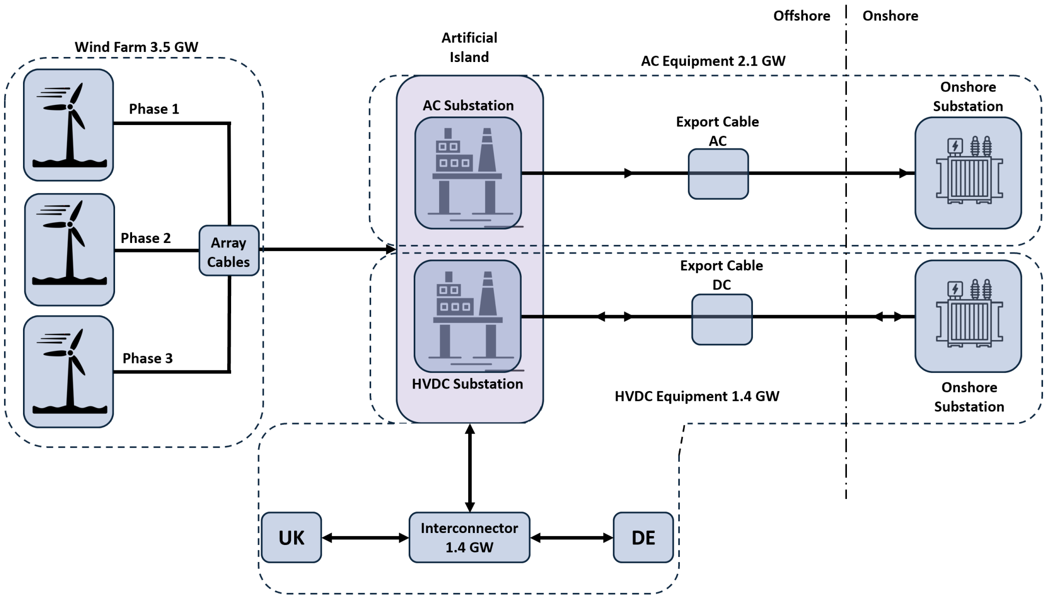


Figure 5.9: PEZ zone Elements Overview, Enhanced Base Case: HVDC interconnector

While at first glance the inclusion of interconnectors appears counterproductive from a purely financial perspective, it must be viewed in the context of broader strategic objectives. Cross-border interconnections contribute to system redundancy, enhance energy security, and facilitate the integration of variable renewable energy sources across different national markets. These objectives align closely with European Union energy policy priorities, which emphasize the need for robust and flexible transnational energy infrastructure to support the transition towards a carbon-neutral economy (Yang, 2022).

Febeliec also acknowledges the importance of interconnectors for achieving higher levels of security of supply and market integration but cautions that the timing and scale of such investments must be carefully considered. In their view, it is essential to ensure that interconnection projects deliver tangible benefits relative to their costs, particularly in markets already experiencing significant upward pressure on consumer electricity prices. They advocate for a gradual and economically justified roll-out of new infrastructure rather than large upfront investments that might strain affordability.

In this context, the integration of interconnectors into the artificial energy island concept offers strategic value over the long term but negatively affects short-term financial performance metrics such as LCOE. The trade-off between immediate financial feasibility and long-term system resilience must therefore be carefully balanced in infrastructure planning decisions.

LCOE Overview

Below is a summary table of the estimated LCOE for the three different base case scenarios:

Base Case	LCOE (EUR/MWh)
Base Case 1: Real-life project	224
Base Case 2: AC Equipment Only	182
Base Case 3: HVDC as Interconnector	237

Table 5.2: Overview of LCOE for Different Base Cases

It is important to note that typical LCOE values for offshore wind projects fall around €120/MWh (Andreas, 2025), underscoring the less favorable feasibility of the current project without improvements. This highlights the need for a more optimal design, possibly a multi-functional island, to unlock synergies and improve financial viability.

5.2. Selection of Port Functionalities

A market analysis of the Port of Bruges operations is conducted to catalog all activities. Once all activities are identified, an MCDA will be performed to select the most promising function for integration on the offshore island.

5.2.1. Identification of potential functions

The Port of Bruges (Zeebrugge) is a critical maritime hub in Europe, offering a wide array of port and logistics functions. Based on a comprehensive review of port operations, the following functionalities have been identified (Port of Antwerp Bruges, 2025):

Port Functionality	Type	Handling On Island	Double Handling
Container handling	Import/(re-)Export	Ship To Ship	Yes
RoRo handling	Import/Storage/(re-)Export	Ship To Ship	Yes
Bulk Cargo	Import/Storage/(re-)Export	Ship To Ship	Yes
LNG handling	Import/Storage/re-Export	Ship To Ship/Pipeline	No
Cruise & Ferry Services	Tourism	-	-
Chemical and foodstuff	Import/Export	Ship To Ship	Yes
Ship bunkering	-	-	No
Naval activities	-	-	No
CCS	Storage/Export	Pipeline To Ship	No
Fishing Activities	-	Ship To Ship	Yes

Table 5.3: Overview of PoB functionalities

Based on the table above, a pre-selection can be made for the MCDA. Certain functionalities are deemed unfeasible for implementation on the island due to spatial constraints, lack of end-use, or logistical inefficiencies. These include (Port of Antwerp Bruges, 2025):

- Container Handling: Requires large storage areas and lacks a direct end-use on the island. Goods would need to be transshipped to the PoB, resulting in unnecessary double handling (Y.-S. Kim and Maeng, 2011).
- RoRo Handling: Similar to containers, this function requires extensive space and has no end-use on the island, leading to redundant transshipment to PoB (Hollrigl and Oberbeck, 1979).
- Dry Bulk Cargo: No direct consumption or processing occurs on the island. As with the above cases, the cargo would be redirected to PoB, creating inefficiencies (Van Vianen et al., 2011).
- Cruise and Ferry Services: The island does not support tourism or leisure activities, rendering this functionality irrelevant.
- Chemical and Foodstuff Logistics: These goods lack an end-use on the island and would eventually be transported to PoB, causing double handling (Maes et al., 2022).
- Fishing Activities: No local consumption or processing capacity exists on the island, again resulting in transshipment to PoB.

The functionalities that remain viable for further consideration include: LNG handling, naval activities, carbon capture and storage (CCS) handling, ship bunkering and vessel maintenance.

5.2.2. MCDA for Remaining Functionalities

After filtering out functionalities that are not implementable or economically viable for offshore deployment, four port functions remain: LNG Handling, CCS Infrastructure, Ship Bunkering and Maintenance, and Naval Activities.

The MCDA is conducted based on five main evaluation criteria: CAPEX & OPEX, Technical Feasibility, Revenue Potential, Environmental Impact, and Strategic Relevance. Weights were assigned to each criterion based on an expert-informed approach. Each function is then scored on a scale from 1 (low) to 5 (high) for each criterion. The weighted total score is calculated accordingly. The full MCDA process can be found in appendix D.

Results

Both LNG handling and CCS infrastructure score highly, with CCS slightly underperforming LNG due to its uncertainty in potential revenue and cost estimates, since the current market for CCS technology is still in development. LNG remains a robust candidate due to its maturity, revenue generation, and strategic role in current energy supply chains. The remaining two functions, ship bunkering/maintenance and naval activities, while feasible, offer comparatively lower strategic and economic incentives for offshore implementation.

The MCDA highlights LNG handling as the most promising functionality for integration on the Princess Elisabeth Island, with CCS infrastructure as a close second.

LNG handling on an offshore artificial island presents an attractive opportunity, particularly given the increasing global demand for flexible and resilient energy supply chains. Offshore LNG transfer, storage, and regasification are already established practices within the industry, typically through the use of Floating Storage and Regasification Units, Single Point Moorings, and Gravity-Based Structures (Adekoya et al., 2024).

However, specific North Sea environmental conditions impose critical operational limitations. The Master Planning materials highlight that offshore weather risks, particularly severe wave and wind conditions, lead to significant downtime for offshore systems without protection, such as single-point moorings. In such conditions, a conventional offshore mooring system would have insufficient operating windows, severely limiting annual throughput (Maritime et al., 2012). Therefore, integrating a sheltered port infrastructure on the artificial island becomes essential to ensuring operational reliability, maximizing available days for LNG transfer and regasification operations.

5.3. Base Case: LNG Terminal

Two base cases are defined for the LNG terminal analysis. The first is a greenfield project involving the development of a new port facility with characteristics, such as dimensions and capacity, comparable to the existing LNG terminal at the Port of Bruges. The second case places the same LNG terminal on Princess Elisabeth Island, deliberately excluding any operational or infrastructure synergies with other island functionalities to serve as a neutral reference point.

To evaluate and compare these configurations, a marginal cost rate per mtpa of regasified LNG is used as a standardized performance metric. Additionally, both the NPV and the payback period are calculated to assess the long-term financial viability of each scenario.

5.3.1. Base Case Onshore LNG Terminal – 6.6 mtpa

The TE analysis process is applied to evaluate the onshore LNG terminal base case in a structured and transparent manner. By applying this method to the greenfield onshore terminal scenario, the analysis establishes a solid reference point for comparing alternative configurations, such as offshore deployment on Princess Elisabeth Island.

System Definition & Supply Chain Breakdown

The onshore LNG terminal is designed to handle an annual throughput of 9 bcm (6.6 mtpa) of natural gas. The facility includes marine access, unloading systems, cryogenic storage, regasification units, and pipeline connection to the gas grid. The required site footprint is approximately 20 hectares. Figure 5.10 gives an overview of the Fluxys LNG terminal and the corresponding system elements.

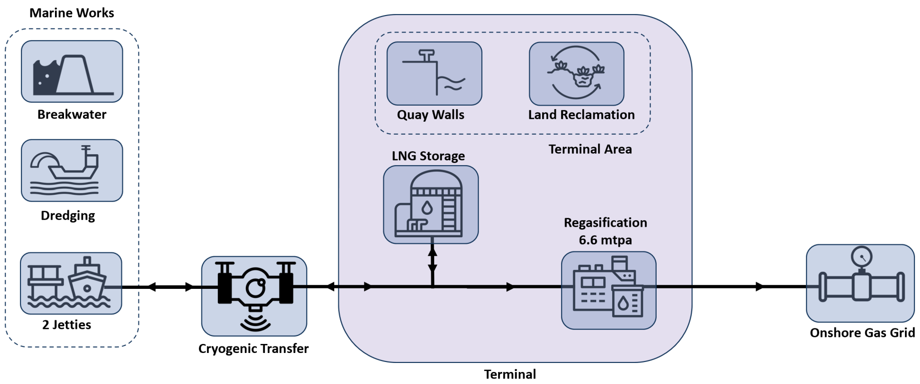


Figure 5.10: Overview Onshore LNG terminal

In appendix E in tables E.1, E.2 an overview is given of all components from the LNG system associated to the base case and their respective CAPEX and OPEX values. The physical and financial characteristics of the components were found in the report by Sooby, 2020, which was obtained through MTBS.

Figure 5.11 illustrates the cost distribution of the key components of the LNG terminal located in the Port of Bruges. The visual clearly highlights that marine works, such as dredging, breakwaters, and jetties, constitute a significant portion of the overall costs, reflecting the extensive infrastructure requirements of an onshore LNG facility.

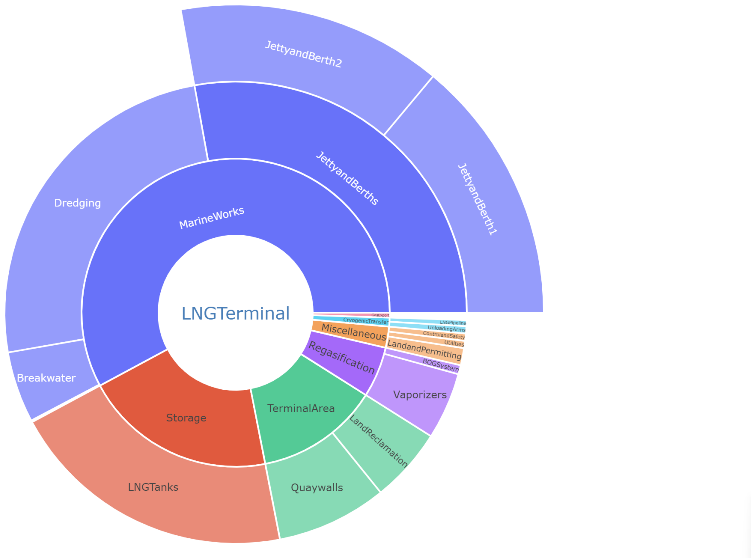


Figure 5.11: Cost Distribution for Onshore LNG Terminal in POB, Project Life: 60 years

Estimated Revenue for a 6.6 mtpa LNG Terminal

The Zeebrugge LNG terminal generates approximately €203 million in annual revenue from three main streams: regasification, berthing and unloading, and transshipment.

Regasification represents the largest share of income. With a send-out capacity of 1,025 MW and a firm tariff of €135,695.71 per MW per year, the regasification revenue is estimated at €139 million annually. This estimate assumes full utilization of terminal capacity, which aligns with Fluxys' statement that the regasification capacity is fully booked until 2042.

Berthing and unloading services for LNG vessels contribute an additional €41 million per year. This is based on 94 ship calls annually, each charged a tariff of €436,263 for unloading LNG into the terminal.

Transshipment activity forms the third major stream, yielding approximately €22.8 million per year. This figure includes both reloading (€12.4 million) and berthing (€10.4 million) for 82 ship calls not related to regasification.

In total, the terminal's estimated annual revenue amounts to €202.8 million. Calculations are based on Fluxys' published tariffs for 2024, an assumed energy conversion of 13.5 MWh per tonne of LNG, and a throughput of 6.6 mtpa.

for the revenues of the LNG terminal a tax rate of 20% is assumed (PwC, 2025).

The detailed calculation of the revenue can be found in appendix E.

NPV and Marginal Cost of Gas

Figure 5.12 displays the free cash flow over time for the base case of the LNG terminal in the PoB.

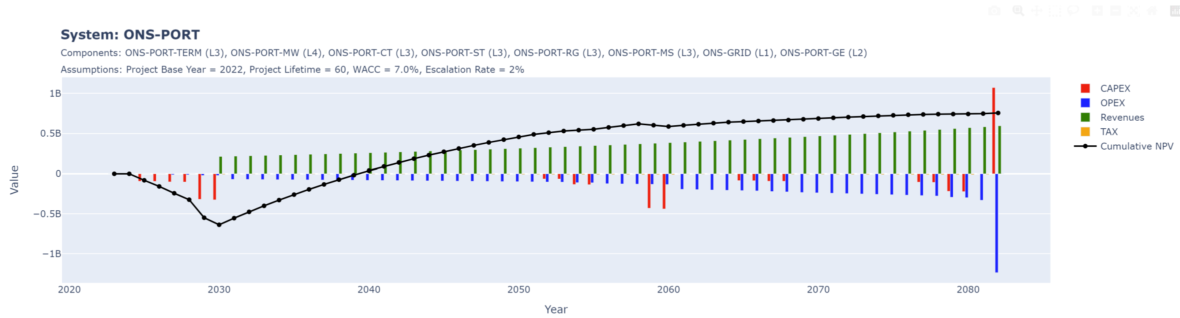


Figure 5.12: Free Cash Flow of Port base case PoB

The final NPV at the end of the project's lifetime amounts to 755 M €. The payback period is approximately 16 years, indicating strong financial feasibility for the current case.

If no revenues are considered for the system, a marginal cost for LNG/natural gas can be estimated using the same formula as the LCOE, but replacing the energy output E with the amount of regasified LNG (6.6 mtpa). This results in a levelized marginal cost of regasified LNG of 29 €/tpa.

5.3.2. Base Case Offshore LNG Terminal Princess Elisabeth Island – 6.6 mtpa

The second base case considers an LNG terminal constructed on an offshore island, without the integration of any additional functionalities.

system Definition & Supply Chain Breakdown

The offshore LNG terminal, situated on a 20-hectare artificial island, is designed to handle an annual throughput of 9 bcm (6.6 mtpa) of natural gas. The facility comprises marine access infrastructure, unloading systems, cryogenic storage tanks, regasification units, and a 40 km subsea pipeline connecting the terminal to the onshore gas grid. The terminal is built on a caisson-based island with sand infill and rock berm protection. Figure 5.13 gives an overview of the offshore LNG terminal and the corresponding system elements.

In appendix E in table E.3 an overview is given of all components from the offshore LNG system associated to the offshore base case and their respective CAPEX and OPEX values. The physical and financial characteristics of the components were found in the report by Sooby, 2020, which was obtained through MTBS.

Figure 5.14 shows the cost distribution of various components of the LNG Terminal in the port of Bruges.

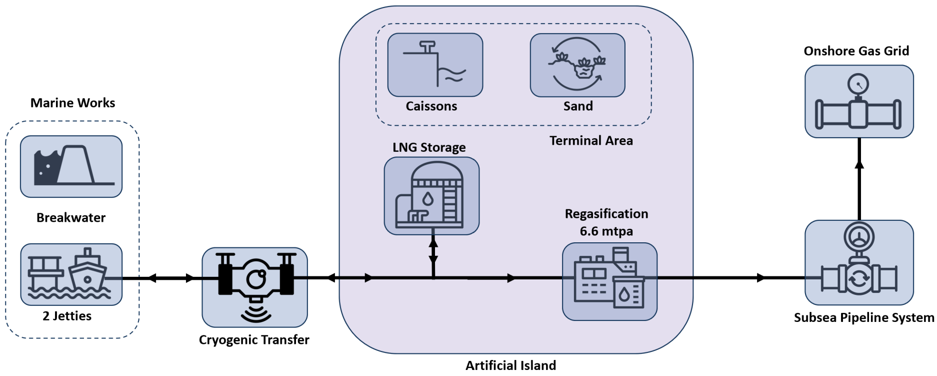


Figure 5.13: Overview Offshore LNG terminal

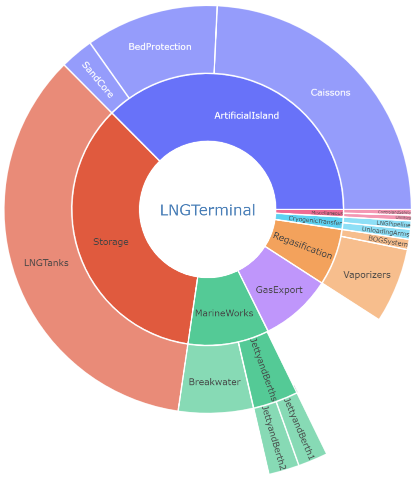


Figure 5.14: Cost Distribution for Offshore LNG Terminal in PE Island

The estimated revenue of the terminal is assumed to be equal to that of the onshore base case, as both scenarios operate with the same capacity.

NPV and Marginal Cost of Gas

Figure 5.15 displays the free cash flow over time for the base case of the LNG terminal on the artificial princess Elisabeth Island.

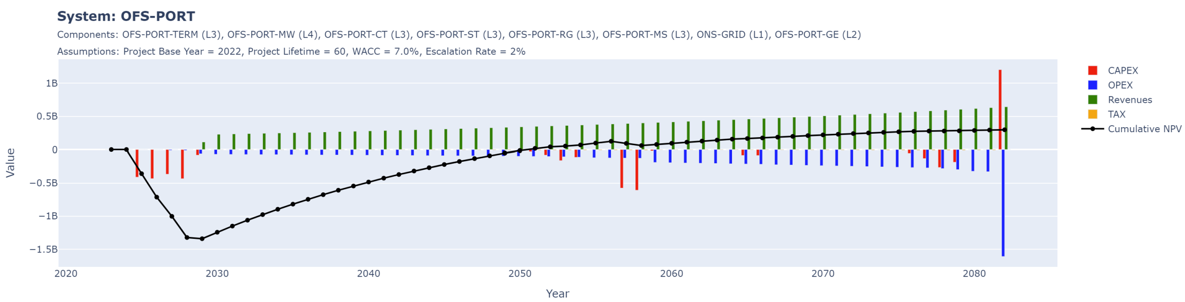


Figure 5.15: Free Cash Flow of Port base case PoB

The final NPV at the end of the project's lifetime amounts to 279 M€. The payback period is approximately 27 years, indicating less strong financial feasibility compared to the onshore case.

If no revenues are considered for the system, a marginal cost for LNG/natural gas can be estimated. For 6.6 mtpa regasified LNG a levelized marginal cost of 39 €/tpa is found.

5.3.3. Comparison Onshore-Offshore LNG Terminal

financial analyses confirm the expected trends: onshore LNG terminals, benefiting from existing port infrastructure and reduced marine engineering requirements, typically achieve lower CAPEX compared to offshore constructions. The onshore terminal base case exhibits significantly lower investment costs for equivalent storage volumes and regasification capacities.

While the offshore terminal could offer some operational advantages, such as reduced port congestion and flexible berthing schedules, these benefits would not translate into substantially higher revenues under normal market conditions, since regasification and storage capacities act as bottlenecks.

Thus, when evaluating base cases in isolation, the onshore LNG terminal provides better expected financial outcomes, confirming its superiority in purely financial terms. This comparison did not yet account for potential synergies in a multi-functional island context. Strategic co-location of energy and port functions may unlock additional value that is not captured in isolated evaluations.

5.3.4. Sensitivity Analysis Payback Period and IRR

To assess the potential long-term revenue development of offshore LNG and port operations on Princess Elisabeth Island, a Monte Carlo simulation was implemented. The model simulates 1,000 stochastic revenue trajectories over a 60-year period, incorporating varying growth patterns and volatility for five distinct scenarios. The baseline for annual revenues is composed of three components: LNG regasification (€139M), berthing services (€41M), and transshipment (€22.8M), totaling €202.8M.

In modeling revenue under uncertainty, we account for the fact that market shocks, such as geopolitical disruptions, supply chain interruptions, or regulatory changes, typically lead to a temporary surge in LNG prices. This is based on the general behavior of commodity and logistics markets under stress: disruptions tend to increase price, allow for more arbitrage opportunities, increase operational risk, but also create uncertainty that dampens new investments. In the stochastic modeling approach, shocks are simulated as upward deviations from a base revenue trajectory, typically followed by gradual recovery periods. The severity, duration, and recovery slope are varied across scenarios to reflect different types of real-world shocks and their plausible outcomes (Andreasson et al., 2016).

Each scenario incorporates a unique time-varying structure of deterministic trends (e.g., growth or decline) and stochastic fluctuations to reflect potential future market behaviors. The stochastic component of the model is introduced using random multiplicative shocks drawn from a log-normal-like process derived via a normal distribution with mean 1 and scenario-dependent standard deviation (σ). This models proportional uncertainty in annual revenues without introducing negative values, which would be unrealistic in this context.

Five market scenarios are considered to assess revenue uncertainty. The Base Case assumes flat revenues with moderate volatility, serving as a neutral benchmark. The Stable Growth scenario assumes a steady annual increase of 1.5% with low but gradually increasing volatility, reflecting a generally favorable market environment that becomes less predictable over time. In contrast, the Geopolitical Shock and Recovery scenario models a sharp revenue spike due to conflict-induced disruptions, followed by normalization and gradual market stabilization over 15 years. The Green Transition captures a structural decline in fossil fuel demand, with revenues falling progressively as climate policy and market preferences shift. Finally, the Volatile Cycles scenario simulates 15-year boom-bust cycles, mirroring the inherent cyclicality of commodity markets, with consistently high volatility emphasizing the importance of strategic investment timing. The complete description of the distributions and associated revenue scenarios can be found in appendix E.

Results

The 2D Density Heatmap of IRR vs Payback Period in figures 5.16 and 5.17 visualizes the joint distribution of IRR and Payback Period for the different scenarios of the two base cases. The analysis assumes a

WACC of 7%, a project life of 60 years, and an escalation rate of 2% for the context of the payback periods. The axes for the figure are as follows:

- X-axis: Represents the IRR distribution showing the spread of IRR values across different scenarios.
- Y-axis: Represents the Payback Period distribution, with values ranging from 10 to 60 years, illustrating the spread of payback periods across the different scenarios.

The heatmap uses a color gradient to show the density of points, where darker regions indicate a higher concentration of values (denser areas), and lighter regions indicate lower concentrations. This provides insight into the relationship between the IRR and payback period, highlighting the likelihood of certain IRR and payback combinations occurring across the different scenarios.

The scenario modeling reveals that across a range of macroeconomic shocks effecting the revenue, the onshore terminal remains consistently viable, maintaining an IRR above the chosen WACC of 7%. Although variations in payback periods are observed, the robustness of the investment is confirmed even under adverse conditions.

Conversely, the offshore LNG terminal exhibits greater sensitivity to negative demand shocks, particularly in scenarios modeling an accelerated transition away from fossil fuels. In such cases, the offshore terminal's IRR may fall below the assumed 7% WACC, threatening standalone financial feasibility. Nevertheless, the long-term adaptability of LNG infrastructure should not be underestimated. As emphasized in industry practice, LNG terminals can be retrofitted to handle alternative liquefied gases such as hydrogen or ammonia, providing a pathway for asset repurposing even in low-carbon future scenarios.

The broader market behavior, as highlighted in Sooby, 2020, indicates that geopolitical instability and commodity price volatility generally enhance the strategic value of LNG storage and regasification assets. During periods of uncertainty, increased price spreads and supply chain disruptions create arbitrage opportunities, which can drive up terminal utilization rates and storage demand.

However, the modeling does not account for extreme cases such as a full-scale global recession, where a collapse in natural gas demand could critically impact terminal revenues. This remains a residual risk inherent in all large-scale energy infrastructure investments.

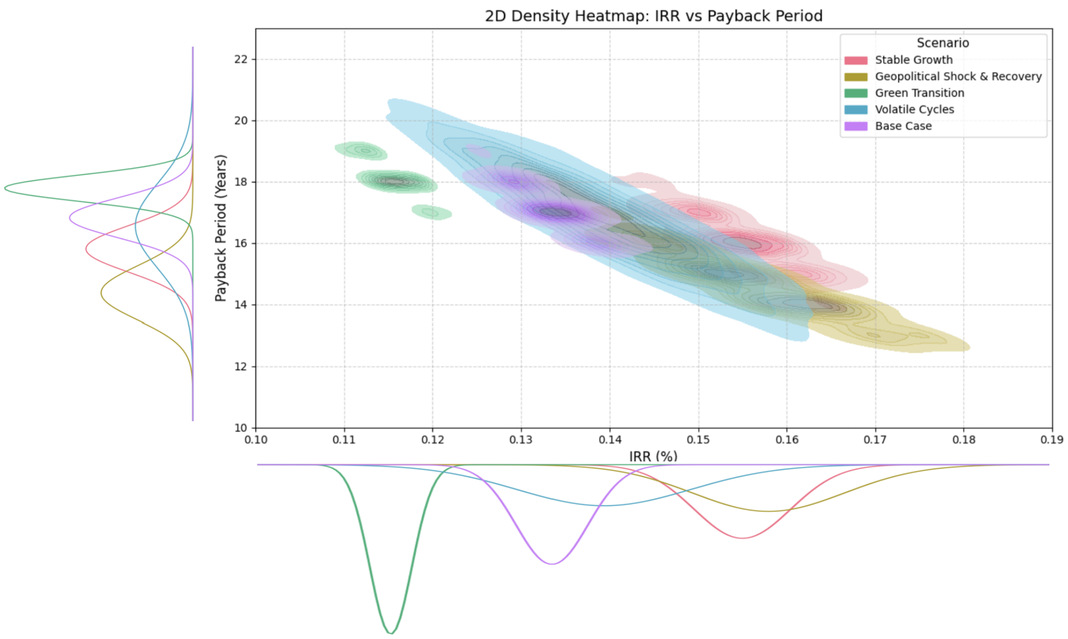


Figure 5.16: 2D Density Heatmap of IRR vs Payback Period for the Onshore LNG Terminal

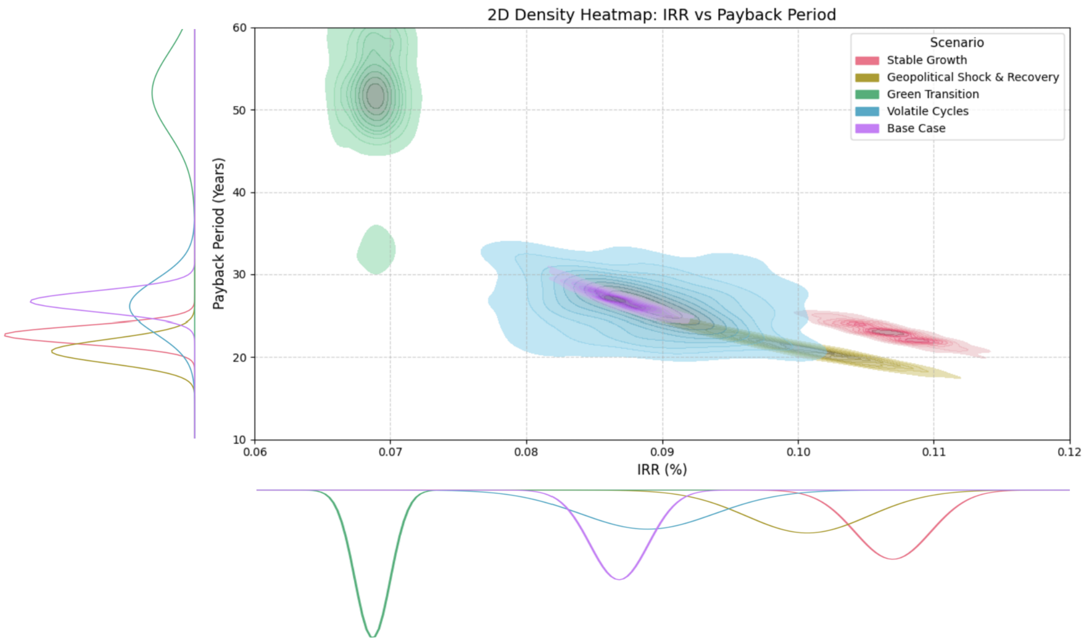


Figure 5.17: 2D Density Heatmap of IRR vs Payback Period for the Offshore LNG Terminal

5.4. Multifunctional Island Design and Synergies

The integration of additional functionalities, specifically a large-scale LNG terminal, onto the offshore energy island introduces opportunities for significant spatial and operational synergies. This section explores how the island's layout can be optimized to support both high-voltage electrical infrastructure and LNG operations, enabling mutual benefits in terms of perimeter cost efficiency, energy use, and infrastructure zoning. The multifunctional design increases the usable area while leveraging shared resources, such as electrical power and construction logistics, to enhance the island's financial feasibility.

Synergies via Island Layout Optimization (Rectangular)

The rectangular layout of the island is optimized to minimize perimeter costs while accommodating both LNG and electrical infrastructure. With a total usable area of 26 hectares, 20 ha for the 6.6 mtpa LNG terminal and 6 ha for HVDC/HVAC systems, the island adopts a square footprint of approximately 510 by 510 meters. This results in a total perimeter of about 2,040 meters.

In this configuration, LNG facilities are positioned along one edge of the island for direct berthing access, with safety buffers and regasification units arranged behind. The HVDC and HVAC stations are placed at the opposite end to maintain functional separation. This setup increases the usable island area from 6 ha (in the base case) to 26 ha, a more than fourfold gain, while the perimeter only doubles, from 1,000 meters to 2,040 meters. Consequently, the number of caissons increases from 23 in the base case to 50 in the combined layout. Although the caisson count and cost approximately double, the fivefold increase in usable area represents a significant gain in spatial efficiency. The full optimization process of the island's layout can be found in appendix F.

Electrical Energy Use of LNG Storage and Regasification

The offshore LNG terminal, with five 180,000 m^3 storage tanks (900,000 m^3 total), consumes electricity for both storage and regasification. Key energy demands include boil-off gas (BOG) handling, auxiliary systems, and electric vaporizers (Sooby, 2020).

Storage is estimated to require 8–10 kWh per cubic meter per year, resulting in an annual consumption of approximately 7.7–9 GWh (Danish Maritime Authority, 2012).

Regasification, using electric vaporizers, consumes about 150–200 kWh per tonne of LNG (Sooby, 2020). For a capacity of 6.6 MTPA, this corresponds to an annual electricity use of roughly 990–1320 GWh.

Combining these figures, total annual electrical demand is estimated at 998–1329 GWh, which corresponds to a continuous electrical load of approximately 114–152 MW.

This steady base load reduces the net export capacity required from the offshore wind park. Originally, the AC export cable system was designed for 2100 MW. Accounting for offshore LNG consumption, the effective export requirement becomes approximately 1948–1986 MW. To maintain system flexibility while optimizing cost, a revised export cable rating of 1995 MW is proposed. The full calculation of the reduced export capacity can be found in appendix F.

While the downsizing effect is relatively modest in this case, the principle is significant. If additional high-electricity-demand functionalities, such as hydrogen production or CO2 liquefaction, were integrated in future developments, even greater optimization of transmission capacity and cost savings could be achieved.

Based on the above reasoning, a conceptual optimal configuration for a multi-functional offshore energy island can be derived. Since approximately 50% of the offshore wind system's capital expenditure arises from the transmission infrastructure, minimizing the required export capacity becomes a key design goal. The full wind farm produces 3.5 GW at peak. If a functionality is added to the island that consumes power continuously, it can be sized optimally at 1.75 GW, exactly half of the wind farm's capacity. This value is optimal because it ensures maximum utilization of both the island functionality and the export infrastructure under varying wind conditions.

When the wind farm is operating at full output (3.5 GW), the on-island functionality directly consumes 1.75 GW, and the remaining 1.75 GW is exported to shore via a reduced-capacity export cable. Conversely, during periods of zero wind generation, the export cable operates in reverse, importing 1.75 GW from shore to sustain the island's functionality. This bidirectional use of a single 1.75 GW cable minimizes CAPEX while ensuring full operability of the system. Although the cable capacity is halved, the total converter station capacity must remain 3.5 GW to manage power flows across different voltage domains: wind farm, island functionality, and shore connection. Therefore, 1.75 GW represents the optimal balance point for continuous demand, maximizing infrastructure efficiency without sacrificing operational reliability.

Curtailment Mitigation through LNG Terminal Integration

In this conservative scenario, we assume full offshore wind generation capacity of 2.1 GW, while the export capacity is limited to 1.995 GW. This inherent transmission constraint results in a structural curtailment risk whenever wind generation exceeds the export limit.

Although the LNG terminal consumes a continuous 114–152 MW of electrical power for its regasification operations, this consumption is steady and non-dispatchable. As such, it cannot be adjusted dynamically to absorb surplus wind energy during peak production periods. Consequently, the presence of the LNG terminal does not actively mitigate curtailment. The local load it represents is already accounted for in the system design. Curtailment levels remain determined by the mismatch between variable wind generation and fixed export capacity, independent of the LNG terminal's constant demand.

Cost Savings from a Combined Port System

In the base case scenarios, each functional configuration (energy and logistics) includes its own dedicated port infrastructure, consisting of quay walls, breakwaters, and associated civil works. These are among the most capital-intensive components of offshore port development.

By integrating both functionalities into a single, shared port system on the island, significant cost savings could be realized. A combined port would eliminate the need for redundant structures, thereby reducing the total length of quay walls and breakwaters required.

Although a combined system may require slightly more robust design specifications to accommodate multiple vessel types or increased throughput, the overall capital expenditure is expected to be lower than the sum of two separate ports. This design approach aligns with the principle of infrastructure co-utilization, which is central to enhancing the financial feasibility of multi-functional offshore islands.

5.5. Evaluation of the Multifunctional Island

Building on the synergies outlined in the previous section, the multi-functional island system is now defined. The overall system retains the key characteristics of the original base cases: Offshore Energy, with 3.5 GW of capacity, consisting of 2.1 GW AC transmission and 1.4 GW HVDC transmission; and Offshore LNG Terminal, with 6.6 mtpa of regasification capacity, supported by 5 storage tanks of 180,000 m^3 each.

Tables G.1 and G.2 in appendix G outline the updated supply chain elements of the multifunctional system. Figure 5.18 illustrates an overview of the combined system and the corresponding system elements.

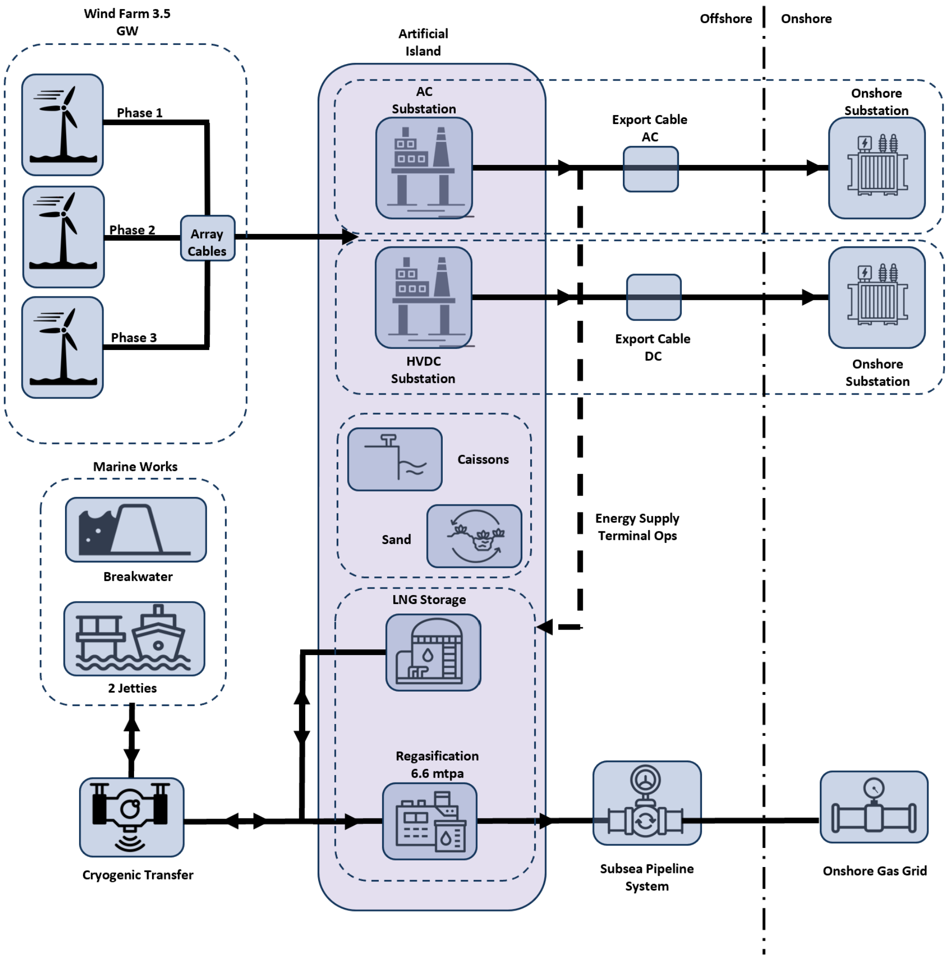


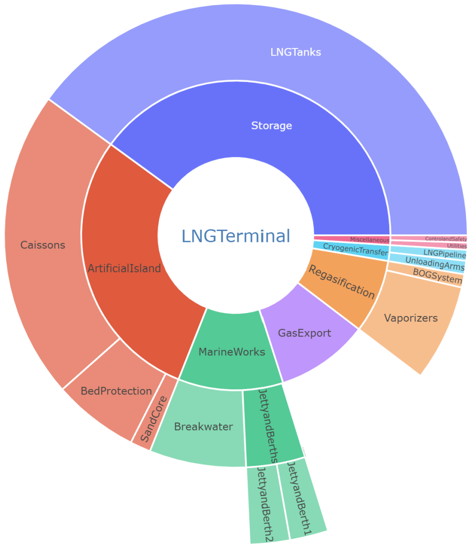
Figure 5.18: Overview Combined System

To facilitate comparison with the base cases, the system is again divided into two functional segments: energy and LNG. Shared infrastructure and associated costs are either allocated proportionally to each functionality or evenly split, depending on the nature of the component.

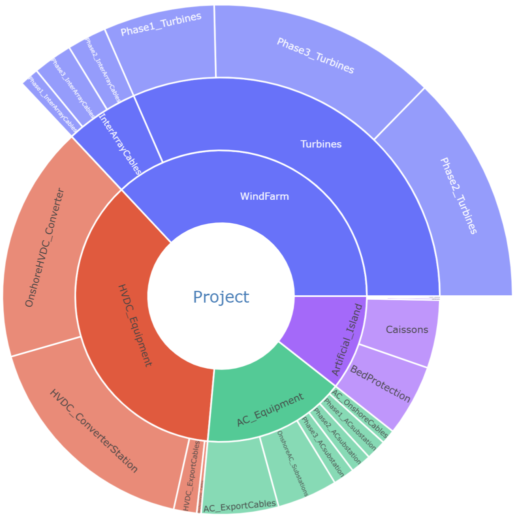
The actual cost allocation will be influenced by the financial feasibility of each function. The objective is to ensure an improved financial position for both functionalities individually, thereby creating a mutual incentive for stakeholders to engage in the development and operation of a complex multi-functional offshore project.

5.5.1. Evaluation Multifunctional System

Figure 5.19 illustrates two cost distributions associated with the two functionalities of the island. Subfigure 5.19a presents the breakdown for the LNG terminal, highlighting the regasification units, storage infrastructure, and associated facilities. Subfigure 5.19b depicts the cost allocation for the energy system, including both the AC and HVDC transmission components.



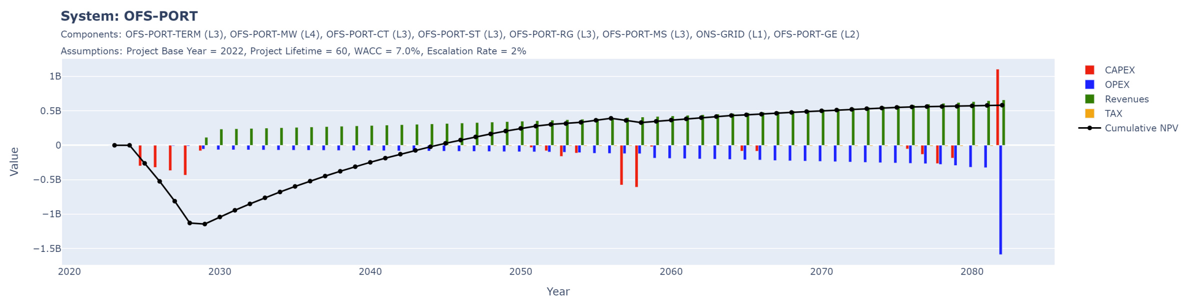
(a) LNG Terminal



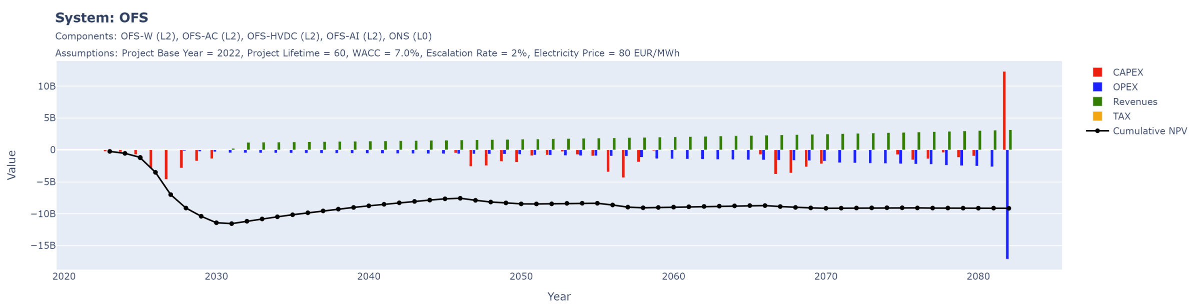
(b) Energy System

Figure 5.19: Cost Distribution of System Components in the Combined Case

Figure 5.20 displays the free cash flows over time for both subsystems in the combined case. Subfigure 5.20a shows the free cash flow profile of the LNG terminal, while Subfigure 5.20b presents the corresponding cash flows for the offshore energy system.



(a) Free Cash Flow of LNG Terminal in Combined Case



(b) Free Cash Flow of Energy System in Combined Case

Figure 5.20: Free Cash Flow Profiles for Combined Case Subsystems

The value of the LCOE for the energy system in the multi-functional case is calculated at €215.5/MWh.

The financial evaluation of the integrated LNG terminal indicates a payback period of approximately 21 years and an IRR of 10%. Under the assumption of a throughput of 6.6 mtpa, the marginal cost of LNG regasification is estimated at 32 €/tpa. The final NPV of the project is calculated at 582 million €.

Results Offshore Wind System

The LCOE for the offshore wind system decreased from 224 EUR/MWh to 215 EUR/MWh, representing an approximate 5% reduction. Although this reduction is a positive development, the resulting LCOE remains significantly above industry-standard benchmark of 120 EUR/MWh for offshore wind energy systems (Andreas, 2025). This indicates that the multi-functional case examined here still faces substantial challenges in achieving cost competitiveness.

The main driver for the elevated LCOE lies in the base case assumptions, particularly the extremely high transmission infrastructure costs. As identified by Febeliec in their 2024 position paper, the cost of HVDC transmission systems for offshore wind has escalated dramatically in recent years.

In the multi-functional configuration evaluated here, some improvement is achieved through cost-sharing: the marginal cost of constructing the artificial island is now distributed between the offshore wind system and the LNG terminal. However, because the island infrastructure only represents a relatively small fraction of the total offshore wind system costs, this sharing effect has only a modest impact on the LCOE.

Additionally, minor cost reductions were realized by slightly lowering the AC transmission export capacity. Since part of the offshore wind electricity is now consumed directly by the LNG regasification terminal, the required export volume to shore is reduced. However, this effect remains limited: only the cable sizing was optimized, while the converter station infrastructure remained unchanged.

Future improvements in multi-functional offshore energy island projects will likely depend on the integration of functionalities with substantially higher on-island electricity consumption. This would allow for greater downsizing of export cable and converter capacities, delivering more meaningful reductions in total transmission costs and, consequently, in LCOE.

Results LNG Terminal

The onshore LNG terminal yields a final NPV of approximately €755 million with a payback period of 16 years at a 7% WACC, reflecting a highly attractive investment. Lower CAPEX and OPEX and simplified construction logistics contribute to its strong financial profile.

The standalone offshore LNG terminal achieves an NPV of approximately €279 million and a payback period of 27 years under the same assumptions. While still viable, its financial attractiveness is diminished by higher construction complexity, greater costs, and increased exposure to operational disruptions.

When synergies between the offshore energy and port functionalities are fully realized, the financial performance of the offshore terminal improves markedly. The integrated multi-functional configuration achieves an NPV of approximately 582 million euros under a WACC of 7%, and the payback period is reduced to approximately 21 years. This substantial improvement highlights the importance of shared infrastructure in enhancing financial viability. Nevertheless, despite these gains, the onshore terminal still maintains the strongest investment case in purely financial terms.

Importantly, the broader strategic benefits of offshore relocation, such as the potential reduction of vessel congestion at the Port of Bruges, the release of valuable coastal land for other uses, and the alignment with long-term decarbonization strategies, were not factored into the financial analysis. These externalities could materially improve the offshore terminal's overall value proposition when considered in an integrated economic and strategic framework.

5.5.2. Uncertainty & Sensitivity Analysis

To account for uncertainty in interconnected energy markets, this subsection introduces a copula-based simulation framework that models the dependency between gas and electricity prices. By fitting statistical distributions to historical TTF gas and EPEX electricity prices and applying copulas, especially those that capture tail dependencies, realistic joint price scenarios can be generated (Grégoire et al., 2008). These scenarios enable revenue stress-testing of offshore wind and LNG terminal operations under correlated market conditions, providing deeper insights into risk exposure during price spikes or demand shocks.

The methodology involves several key steps: collecting price data, fitting marginal distributions to each price series, selecting an appropriate copula function (e.g., t-copula or Clayton) to represent the dependency structure, and finally using Monte Carlo simulation to generate scenarios (Trivedi, Zimmer, et al., 2007). These outputs are then directly linked to revenue models for the offshore wind system, which multiplies sampled electricity prices with annual energy production, and the LNG terminal, where revenues are estimated via a linear function of gas prices. An empirical regression based on Fluxys LNG terminal data confirms a strong positive relationship between gas prices and terminal revenue, particularly during high-volatility years like 2022.

The best-fitting copula is selected by comparing the log-likelihoods across copula families. The Joe copula is found to yield the highest log-likelihood, indicating the best fit for the observed joint behavior of TTF and EPEX prices. The Joe and empirical copula are illustrated in figure 5.21.

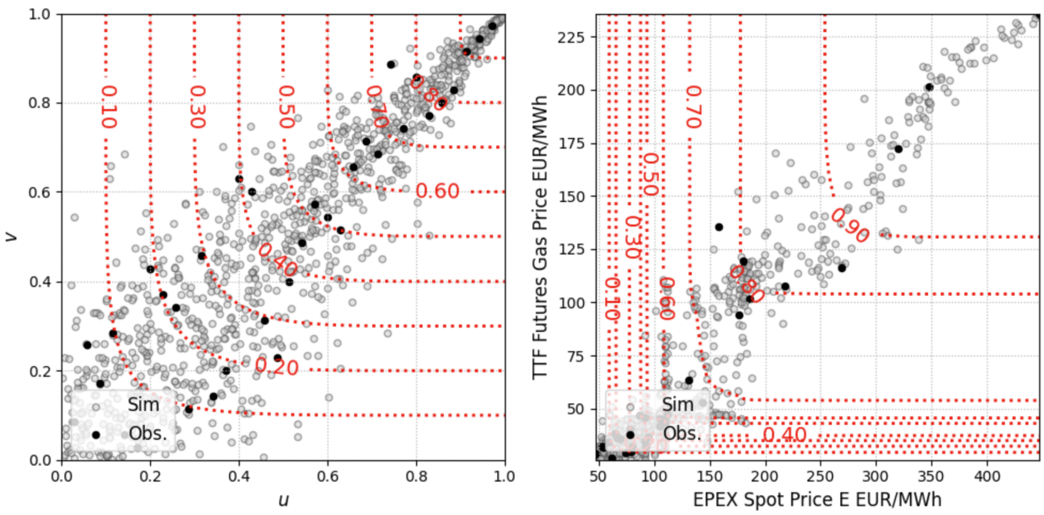


Figure 5.21: Best Fitted Copula: Joe

The transformation of marginal price distributions into uniform variables enables the application of copula theory to construct joint distributions of energy prices. This allows for integrated modeling of economic outcomes across both systems under extreme market conditions, supporting probabilistic sensitivity analysis. The approach strengthens the financial feasibility assessment of multi-functional offshore energy islands by realistically capturing the economic interactions between electricity and gas markets.

Lastly, the following three scenarios are considered for the copula sampling:

1. Just Copula Sampling: This scenario employs a Joe copula with a parameter $\theta = 6.2$, fitted from historical data, to generate the dependencies between the energy prices (EPEX and TTF). The copula is sampled directly without conditioning on any other prices.
2. Conditional Copula (EPEX Conditionalized over TTF): A deterministic forecast of the TTF price is defined for each year over the 60-year period (figure G.5). Based on this forecast, the EPEX price is sampled conditionally over the TTF using the Joe copula, allowing the dependency between these two price dynamics to be reflected.
3. Conditional Copula (TTF Conditionalized over EPEX): A deterministic forecast of the EPEX price is defined for each year over the 60-year period (figure G.5). Subsequently, the TTF price is sampled conditionally over the EPEX price using the Joe copula, capturing the relationship in the reverse direction.

The complete method is presented in appendix G.

Distribution of NPVs

Figure 5.22 shows the NPV distribution for both the LNG terminal and the offshore wind energy system when the values of the EPEX spot price and TTF futures gas price are sampled using the Joe copula. This illustrates how the combined system's NPV varies under different price scenarios derived from the copula sampling.

Figure 5.23a shows the NPV distribution for the offshore wind energy system when the values of the EPEX spot price are sampled using the Joe copula and conditioned on the TTF futures gas price predictions. This scenario allows us to explore how the offshore wind system's NPV is influenced when EPEX prices are dependent on TTF forecasts. Similarly, Figure 5.23b illustrates the NPV distribution for the LNG terminal when the values of the TTF futures gas price are sampled using the Joe copula and conditioned on the EPEX spot price predictions. This provides insight into how the LNG terminal's NPV is affected by the conditional dependency between TTF and EPEX.

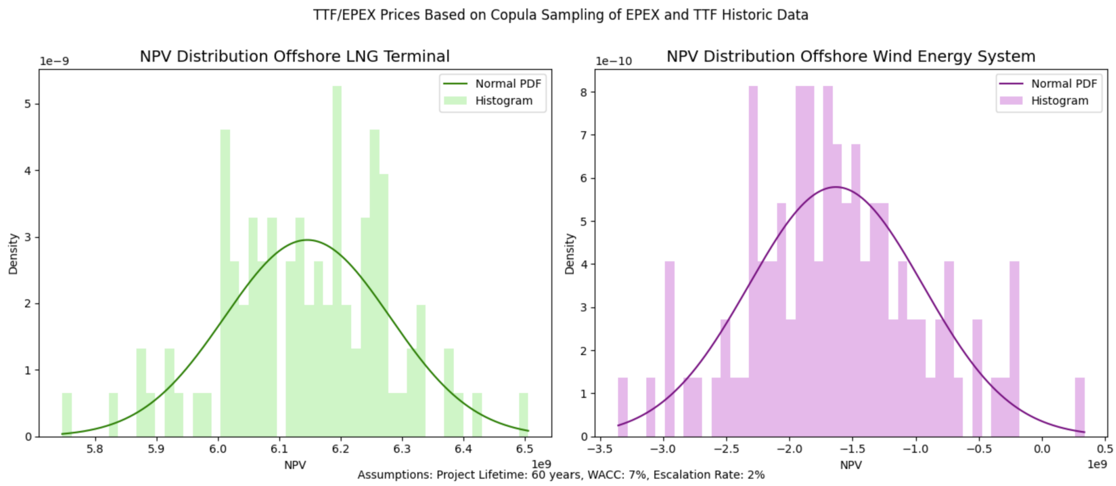
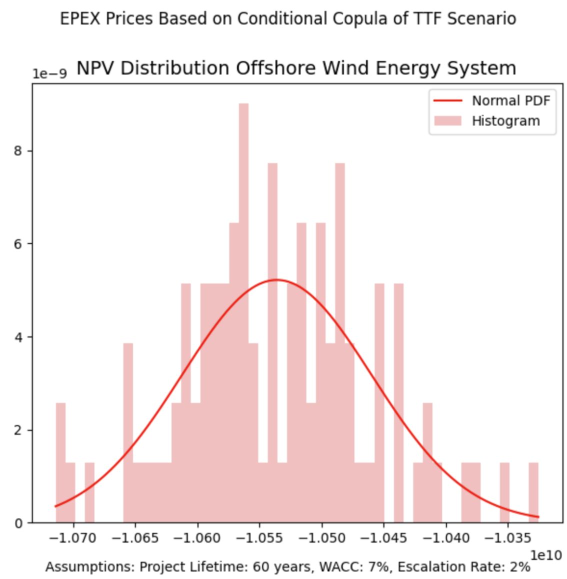
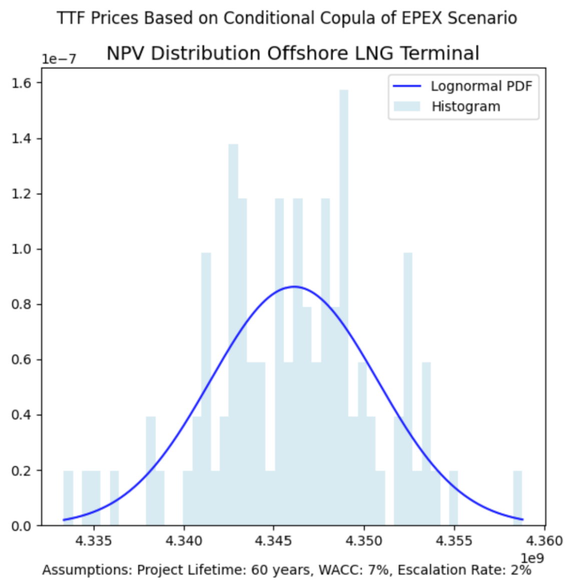


Figure 5.22: NPV Distributions of Combined Case by Copula Sampling



(a) Offshore wind energy system: NPV distribution using conditional sampling where EPEX is conditioned on TTF using the Joe copula.



(b) LNG terminal: NPV distribution using conditional sampling where TTF is conditioned on EPEX using the Joe copula.

Figure 5.23: NPV distributions under conditional copula-based scenarios

In the unconditional sampling scenario, the LNG terminal exhibited robust financial performance with relatively low sensitivity to fluctuations in gas prices. The distribution of NPV outcomes remained stable across the majority of simulation runs, indicating a resilient investment case.

Conversely, the offshore wind system demonstrated high sensitivity to electricity price volatility. The NPV distribution for the wind system showed a wide spread, reflecting the direct exposure of electricity sales revenue to spot market prices. This variability emphasizes the importance of electricity price stabilization mechanisms, such as Contracts for Difference or Power Purchase Agreements, in mitigating revenue risks for offshore wind investments.

For the conditional sampling scenarios, the following results were obtained:

- Gas Prices Conditioned on Electricity Prices: In the scenario where gas prices were conditioned on electricity price forecasts, the financial performance of the LNG terminal deteriorated. The average NPV was lower compared to the unconditional sampling case. This suggests that conditioning gas prices on electricity market expectations introduces additional volatility or uncertainty into the gas price forecasts, negatively impacting LNG terminal revenues. It reflects the fact that while electricity and gas markets are correlated, gas prices are influenced by broader geopolitical and supply chain factors that electricity prices alone cannot fully capture.
- Electricity Prices Conditioned on Gas Prices: In contrast, when electricity prices were conditioned on gas price scenarios, the financial performance of the offshore wind system improved. The average NPV was higher than under unconditional sampling. This result implies that conditioning electricity prices on gas market information may reduce uncertainty in price forecasts, possibly because gas prices remain a dominant marginal cost driver for electricity generation in many European markets. As such, gas price scenarios can provide useful predictive value for future electricity price levels.

These findings highlight an important asymmetry in the systems' sensitivity to market conditions. The LNG terminal appears more exposed to independent gas market dynamics, while the offshore wind system benefits from electricity price stabilization when gas market information is used. Consequently, risk mitigation strategies should account for these different sensitivities: LNG investments should prioritize hedging against independent gas supply risks, while offshore wind revenues can be partially stabilized through careful linkage to gas market indicators or contracts structured around gas-indexed electricity prices.

Remarks on Systemic Risk

Integrating two major energy systems, LNG import and offshore wind transmission, into a single offshore infrastructure platform inherently increases systemic risk. A failure of critical island components, such as the caisson perimeter, foundations, or common utilities, could simultaneously disrupt both gas and electricity supply chains. This compounded risk could have severe national energy security implications, given the strategic role of LNG in winter supply resilience and offshore wind in decarbonization pathways.

While the multi-functional configuration improves economic performance through synergies, it also amplifies the potential downside in extreme failure scenarios. Thus, the design, construction, and maintenance strategies for the artificial island must incorporate higher standards for redundancy, resilience, and contingency planning to ensure the long-term reliability of the combined infrastructure system.

Conclusion

The case analysis demonstrates that integrating synergistic functionalities into the offshore wind scenario leads to an improvement relative to the base case. However, the overall financial feasibility remains significantly below industry benchmarks, limiting its attractiveness for investment. Similarly, the offshore LNG terminal exhibits weaker financial performance compared to its onshore counterpart, offering no compelling financial rationale for pursuing such a development. While the multi-functional island configuration introduces certain benefits, these do not provide sufficient financial justification for incorporating port functionalities within the scope of this project.

Table 5.4 summarizes the key financial metrics of each scenario.

Table 5.4: Comparison of Base and Combined Case Configurations

Configuration	LCOE [€/MWh]	Initial CAPEX [M€]	Payback Period [years]	NPV [M€]
Base Case Energy				
Offshore Wind	224	13,860	–	Negative
Offshore Wind AC Only	182	11,534	–	Negative
Offshore Wind Interconnection	215	16,699	–	Negative
Base Case Port				
Onshore LNG Terminal	–	953	16	755
Offshore LNG Terminal	–	1,651	27	279
Combined Case				
Offshore Wind	214	13,315	–	Negative
Offshore LNG Terminal	–	1,331	21	582

6 Discussion

This chapter begins by outlining the key limitations of the study, followed by recommendations for future research to improve and expand upon the current methodology. Finally, it reflects on how the research contributes to closing the identified gap in assessing the feasibility of multi-functional offshore islands.

6.1. Limitations of Research

This section presents a detailed discussion of the key limitations associated with the research. These limitations pertain to the methodological choices, data availability, scope boundaries, and modeling assumptions that may influence the validity or generalizability of the findings. By acknowledging these constraints, the study aims to provide transparency and guide future research efforts toward addressing these gaps.

Flow of Mass Modeling

While the flow of mass model works under normal conditions, it becomes inadequate when non-normal flows or more complex systems are introduced. For instance, the use of interconnectors in offshore wind systems does not follow the standard flow path from turbine to grid. Instead, it involves grid-to-grid connections, which the current flow of mass model fails to capture. This non-standard flow direction, as well as the amount of capacity associated with the interconnector not matching the full system capacity, is not represented in the existing model. Moreover, the current model is unable to distinguish between different types of capacity (e.g. AC vs. HVDC), which limits its flexibility and accuracy in simulating such systems.

Similarly, the model does not fully capture the dynamics of LNG storage capacity. LNG storage imposes bidirectional flow opportunities, flows from ships to storage, and from storage back to ships, something that the directed graph structure of the current flow of mass model cannot accommodate. As it stands, the model can only capture the flow from the LNG ships to the regasifiers, which then supply the onshore grid. This simplified approach fails to account for the reverse flow from storage to ships, limiting the model's capacity to simulate real-world LNG storage and transportation systems accurately.

In conclusion, the current flow of mass model lacks the flexibility to handle systems with non-standard or bidirectional flows, as well as the ability to model varying capacity types, making it not yet optimal for accurately simulating complex offshore wind and LNG storage systems.

Supplychain Breakdown Method & Cost Coding System

In the industry, there is no consensus on how to properly break down the supply chain. For example, in Elia's report, the supply chain is split vertically, such as wind farm – inter-array cables – island (with converter stations) – export cables (AC + HVDC) – onshore grid. However, in their cost component breakdown model, the categorization is different, including components such as wind farm, AC equipment, HVDC equipment, and the onshore grid. This lack of consistency, even within a single company, highlights the challenge of defining a standardized approach for supply chain breakdowns. For this research, the same cost component system used in Elia's report was adopted. This decision was made to illustrate how the HVDC equipment represents a significant portion of the initial CAPEX, relative to its capacity.

Additionally, a custom cost coding system was developed for the elements in this case study. This was necessary because the ISO19008 standard did not provide a comprehensive coding system for all the elements involved. While this self-made coding system served the purpose for this research, it would be more advantageous to utilize an existing industry standard. Adopting a widely accepted standard would not only improve the model's compatibility with other industry reports but also enhance its transparency and applicability across different projects.

In conclusion, the lack of consensus in supply chain breakdown methods and the use of a custom cost coding system present limitations, particularly in aligning with industry standards. The adoption of a standardized framework would help address these challenges and improve the model's consistency with existing practices.

OpenTESim Software

The OpenTESim software package represents a significant advancement towards more standardized practices within techno-economic analysis. However, due to its inherent complexity, it may not be particularly user-friendly for industry professionals. One of the main challenges is that OpenTESim requires programming knowledge, as it is built on Python. This dependency limits the software's accessibility, as many users in the industry are not familiar with programming. As a result, the potential audience for this tool is reduced to those with technical expertise, which could hinder broader adoption.

Despite these challenges, efforts have been made to improve the software's usability. For instance, the ability to import element and system data from an Excel sheet that follows a standard layout is a step towards simplifying the data input process. However, this does not fully mitigate the need for programming knowledge to operate the software effectively.

In conclusion, while OpenTESim offers powerful features for TE analysis and is a valuable tool for those with the necessary programming skills, its complexity and the need for technical expertise may limit its usability for a wider audience in the industry.

Offshore Wind Energy System

The calculation of produced energy in this research is done in a conservative yet very basic manner, relying on a number of assumptions. While this approach provides a general estimate of the energy output, it lacks the precision needed to account for more complex dynamics that could significantly impact the actual performance of the offshore wind system. For example, there are multiple concerns regarding wake effects within the 3.5 GW wind farm (Laido, 2023). These wake effects, where the wind speed is reduced behind each turbine, can cause a substantial decrease in the energy produced by downstream turbines. As a result, the actual output of the wind farm may be lower than initially estimated.

To improve the accuracy of the energy production calculations, more technical methodologies, such as wake effect modeling and advanced aerodynamic analysis, could be incorporated. These models would account for the interactions between turbines and provide a more detailed and less uncertain view of the system's energy generation potential. By incorporating these technical calculations, the model could offer a more reliable estimate of the wind farm's actual energy output, improving the overall accuracy of the techno-economic analysis.

In conclusion, while the current method provides a conservative estimate, more detailed technical calculations, particularly concerning wake effects, would enhance the precision and reliability of the energy production model.

Level of Detail in System Design

Due to constraints in data availability and time, the level of detail for several components in the system design is limited. For instance, while it is known that the HVDC converter is a major cost driver, the specific parts of the converter system responsible for pushing the cost remain unclear. This lack of detail arises from the unwillingness of companies to disclose sensitive cost information. Consequently, the precise cost breakdown of such critical components is not fully represented in the model.

Similarly, for the LNG terminal, CAPEX values from 2020 were used and escalated accordingly. However, the accuracy of these values in the current market conditions remains uncertain. Over the past four years, LNG demand has increased significantly, likely driving up the demand for related equipment. Whether the supply chain for these items can keep up with this demand, and how prices for such equipment are evolving, is not fully understood at present. This lack of industry insight could have a substantial impact on the case study's results, as seen with the offshore wind system. For example, the cost of offshore transmission equipment has risen significantly, causing the share of CAPEX allocated to transmission infrastructure to increase from 18% to 50% of the total CAPEX in offshore wind projects.

In conclusion, the limited level of detail in the system design, due to data constraints and the volatile nature of certain markets, introduces uncertainties that may significantly affect the results of the case study. Further investigation into these components and closer collaboration with industry stakeholders could help provide more accurate estimates and reduce these uncertainties.

Assessment of Indirect Benefits from Port Space Optimization

The relocation of the LNG terminal to the offshore island not only eliminates the need for onshore LNG infrastructure but also brings a range of indirect benefits that have not been fully considered in this study. For instance, by moving the terminal offshore, there would be a reduction in vessel traffic congestion at the onshore port. LNG carriers often require exclusive access to shipping channels, preventing other vessels from operating in the same area during unloading, thus limiting the overall efficiency of the port (El Chahal, 2020). With the LNG terminal relocated offshore, the freed-up space in the port could allow for more efficient handling of other types of cargo, leading to higher throughput and improved operational flexibility. This optimization could be particularly valuable for ports aiming to accommodate a diverse range of cargoes, such as containerized goods, bulk materials, or renewable energy components.

Another potential benefit is the improved safety and security of port operations. Offshore terminals may be less vulnerable to the risks associated with congestion or accidents in busy ports, such as collisions, environmental hazards, or logistics bottlenecks. Additionally, the increased distance between LNG storage and urban areas could reduce the risk of accidents affecting populated regions, enhancing the safety profile of the operation.

However, quantifying these benefits presents challenges due to their dependency on various external factors, including future cargo demand, changes in global trade patterns, and technological advancements in shipping. While the complexity of modeling these benefits leads to higher uncertainty, future research could explore methods for estimating their value, particularly through scenario modeling that accounts for evolving port usage, changes in shipping regulations, and the integration of other industries.

Market/Revenue Scenarios

In the sensitivity and uncertainty modeling of the case study, several market and revenue scenarios were assumed. However, it is difficult to make definitive statements about the accuracy or correctness of these scenarios. For instance, predicting the EPEX spot price over the next 60 years involves significant uncertainty, and such projections are ultimately speculative. Given the unpredictable nature of energy markets, no certainty or conclusive results can be derived from these assumptions.

That being said, the inclusion of these scenarios does provide valuable insights into the financial robustness of the system. By testing different market conditions, the modeling helps to assess how sensitive the system is to fluctuations in revenue, energy prices, and other external factors. This approach, while speculative, highlights potential risks and helps inform decision-making in the face of uncertainty.

In conclusion, although the market and revenue scenarios cannot be relied upon for precise forecasting, they serve an important role in evaluating the system's resilience under various potential future conditions.

Cashflow Modeling

The cashflow modeling in this research provides a high-level overview of financial feasibility, focusing on CAPEX, OPEX, Revenues, and Taxes. However, key aspects such as funding and financing structures are excluded, limiting the depth of financial analysis.

Key areas not covered include:

- Funding and Financing Structure: The model does not account for the sources of capital (equity, debt, etc.) and their associated costs, such as interest payments and loan schedules.
- Debt Service and Interest Payments: Detailed debt service schedules, including interest rates and loan amortization, are absent, which are crucial for understanding cashflow timing and liquidity.
- Equity Financing: The role of equity investors and their returns (e.g., dividends, capital appreciation) is not included, missing the impact of equity financing on ownership and profitability.
- Tax Considerations: Tax shields from debt financing and potential renewable energy tax incentives are excluded, which could significantly affect net cashflows.

When incorporating financing and funding into the modeling, it is possible to account for multiple stakeholders and evaluate their respective financial cases. This can help in understanding how different funding structures impact various stakeholders' returns, risks, and contributions to the overall project. However, it is important to note that adding financing and funding structures is only necessary when moving from assessing financial feasibility to establishing project bankability. This transition is only relevant if the underlying financial feasibility is found to be positive; otherwise, a more detailed financing structure would not be justified.

To enhance the model, the following steps should be considered: incorporating a detailed breakdown of the financing strategy, including debt and equity components, into the assumptions; adding loan amortization schedules to improve liquidity forecasting and cashflow timing; integrating tax shields, incentives, and jurisdictional tax laws to better reflect the project's effective tax burden; and refining cashflow projections by including working capital, liquidity needs, and contingency adjustments for a more accurate financial assessment.

By addressing these aspects, the cash flow model will provide a more comprehensive view of the project's financial feasibility, accounting for the diverse financial interests of all stakeholders.

6.2. Recommendations for further Research

Integration of a CO_2 Export Terminal

One of the key findings of this research was that, due to the relatively low energy consumption of the LNG regasification process, the potential synergies from reducing the offshore energy export capacity to shore were rather minimal. A promising avenue for further investigation would be the integration of a CO_2 export terminal on the island. In this concept, captured CO_2 would be transported to the island via a pipeline from shore, liquefied using onsite energy, and subsequently shipped to storage-rich regions.

The CO_2 liquefaction process is significantly more energy-intensive compared to LNG regasification. Therefore, such a functionality could create a stronger business case for reducing the capacity required in the energy export systems (e.g., HVDC transmission) (Mun and Lee, 2025, Zou et al., 2025).

This concept was not included in the present case study, as the LNG terminal appeared to offer a more mature and commercially viable opportunity, driven by the established and relatively stable LNG market. In contrast, the carbon market remains immature and is highly sensitive to evolving emissions regulations and policy frameworks, introducing considerable uncertainty into potential revenue streams.

Integration of Energy Storage Systems and Hydrogen Conversion

In the current research, the offshore wind energy system design was primarily constrained to the existing Princess Elisabeth Zone boundaries and did not include energy storage solutions or hydrogen production facilities. For further research, it is recommended to investigate the integration of BESS and/or hydrogen conversion technologies. These systems could potentially contribute to reducing curtailment, stabilizing energy supply, and improving the overall LCOE of the project. By storing excess electricity during periods of low demand or grid congestion, and dispatching it when needed, the financial performance and resilience of the offshore energy system could be enhanced. Moreover, expanding the spatial scope beyond the current zone might reveal additional infrastructure opportunities that were not considered in the present study.

Modeling of Future Renewable Energy Roll-out and Its Impact on the System

Given the long project lifetime of the offshore island (estimated at 60+ years), it is crucial for future research to model the development of additional renewable energy sources and assess their impact on electricity prices and system behavior. As more renewable generation assets are introduced over time, curtailment risks will likely increase, affecting both the revenues and operational stability of the offshore system. This evolution could potentially necessitate the deployment of more large-scale storage solutions, which may influence the overall cost of electricity (Newbery, Group, et al., 2025). Incorporating dynamic future scenarios for renewable energy roll-out and grid infrastructure development would provide a more comprehensive assessment of the long-term financial and technical viability of the project.

Modeling of Operational Downtime and Weather Impacts

In the current study, operational downtime caused by adverse weather conditions, maintenance, or technical failures was not explicitly modeled. However, particularly for offshore terminals and energy systems, storm events and harsh maritime conditions can significantly affect the number of effective operational days per year, thereby influencing both revenues and system utilization rates (Touloumidis et al., 2025). Future research should integrate probabilistic downtime modeling based on historical weather data and operational benchmarks to create a more accurate financial and logistical assessment of the system performance.

Incorporation of Component Engineering into the TE Analysis Model

One limitation of the current techno-economic analysis method is its lack of detailed component engineering, which has not been addressed in this research. The analysis primarily focuses on the high-level economic feasibility and operational aspects but does not integrate the physical characteristics and engineering design of individual system components. Future research could benefit from incorporating component engineering into the TE analysis model, specifically by embedding the physical properties and performance specifications of key system elements (e.g., turbines, converters, storage systems) into the OpenTESim software framework.

Including detailed engineering data such as power ratings, operational limits, efficiency curves, and physical sizing of equipment would allow for a more nuanced understanding of how each component influences the overall system performance and cost structure. This could lead to more accurate simulations of component interactions, degradation over time, and maintenance schedules, improving the reliability and precision of the model's financial predictions. Moreover, incorporating engineering design could highlight areas where cost reductions or operational efficiencies might be achieved through design optimization or technology advancements.

Furthermore, by integrating physical characteristics into the model, the research could explore more specific engineering trade-offs, such as the impact of system size on performance, scalability of key components, and the feasibility of adopting emerging technologies (e.g., next-generation HVDC converters or advanced storage systems). Such a comprehensive approach would allow for more informed decision-making and a deeper understanding of the technical constraints that influence the long-term viability of the project.

6.3. Research Gap Closure

This section elaborates on how the developed methodology addresses the gaps identified, particularly regarding transparency, standardization, and the need for a structured assessment framework for multi-functional offshore energy islands. Furthermore, it discusses the improvements achieved in uncertainty and dependency modeling and highlights key insights derived from the application to the Princess Elisabeth Island case.

6.3.1. Transparency Achieved

A key shortcoming in many previous techno-economic studies of offshore energy infrastructure is the limited transparency in the underlying assumptions. This project has addressed this issue by explicitly incorporating financial and technical assumptions directly into the model outputs. In particular, all cash flow-related figures now include annotations stating the key assumptions, such as WACC, base year, escalation rates, and electricity price. This ensures that readers and stakeholders can clearly interpret what drives the financial results. Given that financial assumptions have a significant impact on outcomes, as evidenced through the case's extensive uncertainty analysis, transparent communication of these parameters is essential.

A significant improvement in transparency was also achieved in the calculation and presentation of the LCOE. Many studies provide the system capacity (in MW) but omit explicit mention of the assumed annual energy output (E, in MWh), which is a critical component of the LCOE formula. In contrast, the method developed in this work includes a simple yet transparent calculation of E, along with a statement of the assumptions influencing its value, such as the commissioning schedule and operational efficiency. This allows stakeholders to better understand the risks and dependencies associated with energy output projections and, by extension, LCOE estimates.

Moreover, for large-scale offshore projects, such as the case with 350 wind turbines, capacity tracking over time has been incorporated. Unlike smaller or single-phase projects, offshore wind farms with many components typically experience staggered commissioning. This can cause a significant delay in achieving full operational capacity, impacting the economic performance during initial years. The model now accounts for these ramp-up dynamics through a mass flow approach, which allows for partial capacity operation in early phases. The system's operational output is tracked and visualized over time, incorporating construction and operational constraints. This enhances transparency and ensures consistency in financial modeling, especially with regard to phased CAPEX recovery and partial revenue generation.

6.3.2. Standardization Achieved

Another critical gap addressed is the absence of a standardized approach to modeling and communicating multifunctional energy island designs. While ISO 19008 is occasionally referenced in the literature, it lacks the granularity required to represent complex, multi-use offshore systems. As no suitable standard existed, a custom standardization framework was developed as part of this study.

This new standard allows for consistent representation of supply chain components and indicates the level of detail at which each component is defined. Cost elements are coded and categorized, enabling clear communication of system boundaries and modeling depth. This improves the traceability of inputs and facilitates model comparison across different case studies or project phases.

Additionally, the cash flow modeling approach has been significantly refined. More components were added to represent a broader set of system functionalities and interactions, enabling deeper financial analysis. Importantly, the methodology adheres to industry-standard financial practices, ensuring the robustness and comparability of outcomes. This adherence provides credibility and supports use by project developers, policymakers, and investors.

6.3.3. Framework for Assessing Multifunctional Islands

A central contribution of this research is the development of a comprehensive framework for assessing the techno-economic feasibility of multi-functional offshore islands. As identified in the literature review, no such framework currently exists. Chapters 3 and 4 of this thesis lay out a structured methodology that integrates widely accepted assessment tools, such as LCOE, NPV, payback period, MCDA, and benchmarking, into a unified framework tailored for multifunctional systems.

The method balances rigor with usability: it leverages familiar tools already known to stakeholders in the offshore energy sector, while remaining flexible and adaptable across various use cases. It is not tailored to one specific case and can be applied to a broad range of island configurations and regional contexts. As demonstrated in the case application, the framework allows for systematic exploration of alternative configurations and their financial viability, supporting both early-stage planning and policy development.

6.3.4. Uncertainty and Dependency Modeling Framework

A further innovation lies in the integration of uncertainty and dependency modeling using the OpenTEsim platform developed in Python. Compared to traditional tools such as Excel, Python offers substantial advantages in terms of scalability, speed, and the ability to simulate complex interdependencies. For example, the platform allows the user to rapidly generate distributions of potential outcomes for financial indicators under varying assumptions.

This is especially valuable in large-scale offshore projects where key variables (e.g., electricity price, construction delays, fuel costs) are not independent. The model supports advanced dependency modeling techniques such as copula functions, which capture non-linear correlations between variables. This significantly enhances the realism and predictive power of scenario analyses. While Excel-based models can attempt similar functionality, they tend to become overly complex or computationally inefficient when dealing with multiple layers of stochastic variables and dependencies.

6.3.5. Insights Gained from the Case Application

The application of the framework to the Princess Elisabeth Island case yielded several key insights into the feasibility and potential of multi-functional offshore islands. By systematically evaluating various design alternatives, the study demonstrated where multi-functionality can add financial value, and where it may fall short.

Specifically, the incorporation of an offshore LNG import terminal did not result in significant financial gains under the current assumptions. However, the process highlighted several areas for optimization in LNG terminal design and integration. On the other hand, more promising results were observed when large energy-consuming functionalities were co-located on the island. These uses reduce the need for costly transmission infrastructure and can enhance revenue stability by anchoring demand at the generation site. Such design principles may guide future offshore infrastructure planning by aligning energy generation with proximal energy demand.

In sum, the case study has validated the utility of the framework and demonstrated its capacity to generate actionable insights. The transparent, standardized, and adaptable nature of the methodology represents a significant step forward in the techno-economic assessment of multi-functional offshore energy islands.

7 Conclusion

7.1. Conclusion Study

This study set out to develop a robust, scalable method to assess the techno-economic feasibility of multi-functional offshore islands that integrate both energy and port functionalities, a topic insufficiently addressed in current literature and practice. By systematically answering the central research question and its sub-questions, this research not only proposed a novel framework but also demonstrated its application to the Princess Elisabeth Island, offering actionable insights for policymakers, developers, and the broader offshore infrastructure community. The research shows that multi-functionality, when carefully planned and evaluated, is not just feasible, it is a strategic imperative for future-proofing offshore infrastructure in the context of the energy transition.

1. What methods have been used to assess the techno-economic feasibility of offshore islands?

Current methods for techno-economic assessments (TEAs) in offshore infrastructure are largely sector-specific, typically tailored to either energy systems or port operations. No comprehensive methodology currently exists that integrates both domains in a single, coherent framework. This study addressed this gap by adapting the TEA approach to accommodate hybrid offshore systems, incorporating physical design, financial modeling, and performance evaluation within a standardized process. The integration of OpenTESim into the framework made it modular and transparent, enhancing reproducibility and allowing for nuanced scenario modeling across multiple configurations.

Crucially, this work went beyond isolated component-level assessments by explicitly modeling system interdependencies and synergies, such as joint infrastructure usage and co-located operations, which have previously been underexplored in the literature. This methodological contribution lays a foundation for future studies seeking to move beyond siloed analyses and toward a holistic, system-level view of offshore development.

2. What industry standards can be used to develop a more transparent evaluation method?

One of the key challenges identified in the literature and industry practice is the lack of standardized system breakdown structures that encompass both energy and port systems. Existing standards are fragmented and typically tied to specific technologies or sectors. To bridge this gap, this study developed a custom cost breakdown and coding system, ensuring that the model components were traceable, logically structured, and suitable for multi-functional offshore projects.

This innovation not only improves transparency and comparability across different design options but also proposes a pathway toward standardization, enabling a clearer understanding of capital and operational cost drivers. The inconsistency of system partitioning observed in industry underscores the relevance of this contribution, particularly as integrated offshore infrastructure becomes more prevalent.

3. What are the potential energy operations and port functionalities that offshore islands can accommodate, and how can they be systematically identified and prioritized?

The research identified a clear asymmetry in the feasibility of different offshore functionalities. While container and dry bulk operations pose logistical and cost-related challenges on islands due to transshipment inefficiencies, gaseous and liquid operations, especially those that can utilize pipeline infrastructure, are highly compatible with offshore settings. Furthermore, the potential of offshore islands as transshipment hubs for maritime traffic emerged as a strategic opportunity, particularly in congested or draught-limited port environments.

To systematize functionality selection, a Multi-Criteria Decision Analysis approach was developed and implemented. This not only introduced a structured way to evaluate trade-offs between economic, technical, and spatial factors but also demonstrated how strategic prioritization of functionalities can optimize the value proposition of offshore islands. In doing so, the study provides a replicable model for future infrastructure planners aiming to align offshore projects with national energy and port strategies.

4. What alternative configurations of offshore islands can integrate these functionalities, and how can their technical, energy, and economic feasibility be assessed using a standardized method?

This research showed that multi-functional configurations are not only technically feasible but also capable of delivering superior financial performance when compared to single-purpose base cases if designed strategically. By structuring the comparison between base and hybrid configurations using a consistent set of capacity and physical parameters, the analysis ensured methodological rigor and comparability.

The study was able to quantify synergies, such as reduced caisson use, consolidated logistics, and shared export infrastructure, and translate these into measurable cost reductions and improved project viability. These insights were made possible through a standardized TEA framework that incorporated both deterministic and probabilistic analyses, enabling a robust comparison of different island designs under various market and operational conditions.

5. How can the proposed method be applied to the case of Princess Elisabeth Island to evaluate its impact on economic and energy feasibility?

The application of the TEA framework to the Princess Elisabeth Island served as a real-world test of the method's validity and usefulness. The case study demonstrated how an offshore island originally envisioned for energy transmission could be reconceptualized as a multi-functional hub, with an LNG terminal identified as the most viable additional functionality through the MCDA approach.

The comparative modeling of three configurations, onshore LNG terminal, offshore standalone terminal, and hybrid island, enabled a clear articulation of the financial and operational implications of multi-functionality. Synergies identified through the modeling led to a significantly improved business case in the hybrid scenario, showcasing reduced infrastructure costs and more favorable financial metrics such as LCOE, IRR, and payback period.

Moreover, the integration of uncertainty modeling and scenario analysis allowed the study to explore long-term risks and variability in energy markets. By combining deterministic modeling with Monte Carlo simulations, the study provided a more nuanced understanding of the project's resilience under fluctuating energy prices and regulatory scenarios. This forward-looking approach reflects best practice in infrastructure finance and risk management and sets a precedent for future offshore project evaluations.

How can the techno-economic feasibility of multi-functional offshore islands, integrating energy and port functionalities, be assessed?

This research demonstrated that the techno-economic feasibility of multi-functional offshore islands can be systematically assessed using a structured, modular framework that integrates physical design, financial analysis, and uncertainty modeling. The study bridged a critical methodological gap by tailoring techno-economic assessment tools to hybrid offshore systems, accommodating both energy infrastructure and port operations within a single platform.

The developed method combines industry-informed cost breakdown structures, robust scenario analysis, and reproducible modeling logic to deliver a transparent and transferable evaluation tool. When applied to the Princess Elisabeth Island, the framework validated its practicality and provided novel insights into how multi-functional configurations can generate economic synergies, reduce CAPEX, and enhance the financial resilience of offshore projects over long lifespans.

This study moves beyond conventional project evaluation by emphasizing system interconnectivity, long-term uncertainty, and strategic infrastructure planning. In doing so, it makes three core contributions: (1) a replicable methodology for integrated offshore TEA, (2) a set of decision-support tools for identifying viable functionality combinations, and (3) a demonstration of how hybrid designs can outperform conventional single-use models. Together, these contributions provide both an academic foundation and a practical roadmap for advancing multi-functional offshore development in the era of the energy transition.

7.2. Outlook & Recommendations

The findings of this research provide valuable insights into the techno-economic feasibility of multi-functional offshore islands, integrating both energy and port functionalities. As we move towards more sustainable and economically viable offshore solutions, the methodology developed in this study presents a key opportunity for expanding and optimizing offshore infrastructure systems. The structured and flexible TEA framework that was developed proves to be a robust tool for evaluating the technical, economic, and energy feasibility of multifunctional offshore islands, making it a key asset for future offshore projects.

For industry stakeholders, policymakers, engineers, and investors, the TEA framework offers a reliable and adaptable tool for evaluating new offshore infrastructure projects. Its flexibility ensures that it can be tailored to various geographical locations, market conditions, and project scales. To facilitate the adoption of this framework, it is essential to continue developing user-friendly interfaces and standardized tools that streamline data input and analysis. Collaboration with industry partners to refine assumptions and align results with industry practices will further strengthen the applicability of the method.

The concept of multi-functional offshore islands holds great promise, particularly in the context of reducing operational costs and supporting the transition to a low-carbon economy. However, successful implementation will require overcoming certain challenges. For example, while this study focused on LNG terminals, further analysis is needed to explore the integration of other port functions, such as CCS export terminals, into offshore islands. Additionally, long-term performance considerations, such as maintenance and system degradation over the lifetime of the project, need to be addressed to ensure the durability and sustainability of these systems.

The practical application of this research also hinges on strong collaboration between various stakeholders. Government bodies, energy producers, and port operators must work together to create a clear regulatory framework that supports the dual purpose of energy and port infrastructure. Financial incentives and investment models will also be crucial to support the development of multi-functional offshore islands. This will enable the creation of more efficient, sustainable, and economically viable offshore infrastructure solutions.

In conclusion, multi-functional offshore islands represent a compelling opportunity to optimize the use of offshore space for both energy generation and port operations. The findings of this study underscore the potential of such systems to improve financial and energy feasibility, streamline operations, and contribute to sustainability goals. As offshore infrastructure continues to evolve, multi-functional islands can play a key role in shaping the future of energy and logistics at sea.

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A
Techno-Economic Analysis Modeling

A.1. Physical Breakdown: Offshore Energy Systems

In tables A.1, A.2 and A.3 a detailed breakdown of the components involved in offshore energy production, storage and transmission, with their corresponding cost coding and if existent, ISO19008-2016 code, is given.

A.2. Port Supply Chain breakdown

Table A.4 highlights the terminal layout needs for various port functions. It provides an overview of the key factors to consider, such as berth orientation, port location, connections to storage or processing facilities, and the relationship of the terminal to nearby urban areas. This information is essential for understanding how terminal layouts can optimize operational efficiency while minimizing environmental and social impacts (Van Koningsveld et al., 2023).

Table A.5 identifies the facilities and equipment required for each terminal type. This information helps in assessing the infrastructure and logistical needs for each type of operation (Van Koningsveld et al., 2023).

Table A.1: Detailed Supply Chain breakdown Offshore Energy (Part 1)

Name	**Type**	**Description**	**ISO Code**	**Cost Code**
Wind Farm	Component (L1)	Production of wind energy	AW	OFS-W
Wind Turbine	Element (L2)	Offshore wind turbines larger than their onshore counterparts. Recent advancements, such as the SG 14-222 DD and HaliadeX (up to 15 MW), have increased the capacity (Vernova, 2024, Siemens Gamesa, 2024).	AWA	OFS-W-T
Rotor Blades	Sub-Element (L3)	Made of composite materials such as fiberglass (Barter et al., 2023)	AWAA	OFS-W-T-RB
Nacelle	Sub-Element (L3)	ouses the generator and electrical components (Bhattacharya, 2014)	AWAA	OFS-W-T-NA
Tower	Sub-Element (L3)	Provides structural support, often made from steel or concrete	AWAA	OFS-W-T-TO
Foundation	Element (L2)	Essential for their stability in harsh marine conditions. Foundation types include (Byrne and Houlsby, 2003)	AWAB	OFS-W-F
Mono-pile	Sub-Element (L3)	Most common for depths up to 30 meters (Wu et al., 2019)	AWABA	OFS-W-F-MP
Jackets	Sub-Element (L3)	Lattice structures for deeper waters (Thomsen, 2014)	AWABA	OFS-W-F-J
Floating Platforms	Sub-Element (L3)	Used in deeper waters, these are anchored with mooring lines (Lei et al., 2024)	AWABB	OFS-W-F-FP
Inter-Array Cables	Element (L2)	Link individual turbines to offshore substations and are typically buried in the seabed to minimize visual impact (Apostolaki-Iosifidou et al., 2019)	AEF	OFS-W-IAC
AC Equipment	Component (L1)	AC converter, transmission and export infrastructure (Ackermann, 2005)	-	OFS-AC
AC Substation	Element (L2)	Its primary function is to step up the medium-voltage electricity from the wind turbines to a higher voltage, facilitating efficient long-distance transport (Hamadi et al., 2019).	AWBA	OFS-AC-SUB
AC Collection Cable	Element (L2)	transmitting the AC electricity converted by the substation to the next substation or converter. Typically constructed from copper or aluminum. The efficiency of AC collection cables generally ranges between 95% and 99% (Apostolaki-Iosifidou et al., 2019).	AEF	OFS-AC-C
HVDC Equipment	Component (L1)	HVDC converter, transmission and export infrastructure	-	OFS-HVDC
HVDC Converter Substation	Element (L2)	HVDC substation is employed when electricity must be transmitted over long distances (Van Hertem et al., 2016).	AWBA	OFS-HVDC-SUB
HVDC Cable	Element (L2)	The average efficiency of HVDC cables typically ranges between 95% and 98%. Transmission losses in HVDC cables increase with distance (De Alegría et al., 2009).	AEF	OFS-HVDC-C

Table A.2: Detailed Supply Chain breakdown Offshore Energy (Part 2)

Name	**Type**	**Description**	**ISO Code**	**Cost Code**
Electrolysis System	Component (L1)	Production of Hydrogen	ERVU	OFS-ES
Electrolyser	Element (L2)	Offshore electrolyzers convert renewable energy into hydrogen	-	OFS-ES-E
Proton Exchange Membrane Electrolyzers	Sub-Element (L3)	PEMEL: Quick response but expensive (Lange et al., 2023; Sayed-Ahmed et al., 2024)	-	OFS-ES-E-PEMEL
Alkaline Electrolyzers	Sub-Element (L3)	AEL: Low cost and long lifespan (Bodner et al., 2015)	-	OFS-ES-E-AEL
Solid-Oxide Electrolyzers	Sub-Element (L3)	(SOEC): High efficiency, still in demonstration phase (Nechache and Hody, 2021)	-	OFS-ES-E-SOEC
Desalination Unit	Element (L2)	Remove salt and other minerals from seawater or brackish water, making it suitable for use in electrolysis (Karagiannis and Soldatos, 2008).	BCDD	OFS-ES-DU
Compressor Unit	Element (L2)	Responsible for compressing the hydrogen gas produced during the electrolysis process (Nguyen et al., 2016)	BDAGE	OFS-ES-CU
Storage Unit	Element (L2)	contain the hydrogen gas produced during the electrolysis process (Makridis, 2016)	BBAB	OFS-ES-SU
Compressor After Storage	Element (L2)	After storage, an additional compressor used to increase the pressure of the hydrogen for injection into a gas pipeline (Wachel and Von Nimitz, 1981)	-	OFS-ES-CAS
BESS	Component (L1)	Battery Energy Storage System	-	OFS-BESS
Battery Elements	Element (L2)	lithium-ion batteries, lead-acid batteries, and sodium-sulfur batteries (Yang et al., 2022)	-	OFS-BESS-B
Inverter	Element (L2)	responsible for converting the DC electricity stored in the batteries into alternating current AC electricity (Datta et al., 2021)	-	OFS-BESS-IN
Substation	Element (L2)	Responsible for stepping up or stepping down the voltage to ensure compatibility with the grid (Enel Green Power, 2023; Sattar et al., 2020)	AWBA	OFS-BESS-SUB

Table A.3: Detailed Supply Chain breakdown Offshore Energy (Part 3)

Name	Type	Description	ISO Code	Cost Code
Offshore Artificial Island	Component (L1)	Island infrastructure used for electricity transmission and storage	-	OFS-AI
Island Structural Body	Element (L2)	Structural body	-	OFS-AI-SB
Heavy/Light Revetment	Sub-Element (L3)	Protectional measure for island base	-	OFS-AI-B-RV
Caisson	Sub-Element (L3)	Used for perimeter construction of island	AEDA	OFS-AI-SB-C
Rock Berm	Sub-Element (L3)	Protection measure for island footprint	-	OFS-AI-SB-RB
Sand	Sub-Element (L3)	Used to fill up core of island in case of caisson use for perimeter	BCM	OFS-AI-SB-S
Floating Barrier	Sub-Element (L3)	Used for design of floating offshore island	-	OFS-AI-SB-FB
Island Port	Element (L2)	Allows for accessing the island	-	OFS-AI-PO
Breakwater	Sub-Element (L3)	Protection of inner port area against marine conditions	-	OFS-AI-PO-BW
Quay Wall	Sub-Element (L3)	providing a stable platform for vessels to dock, load, and unload cargo or passengers	SB	OFS-AI-PO-QW
Island Operational Facilities	Element (L2)	e.g. Cable/pipe landing facilities	-	OFS-AI-OPF
LNG Regasification Terminal	Component (L1)	Handling of LNG including storage, transshipment, regasification and distribution	-	ONS-LNG / OFS-LNG
LNG Regasification System	Element (L2)	Facilities for LNG vaporization are used in LNG import terminals	BKBB	-LNG-RG
Vaporizers	Sub-Element (L3)	gas fired / electricity powered vaporizes most often of the submerged combustion type	BKBB	-LNG-RG-VP
BOG	Sub-Element (L3)	Boil of gas handling: indirect or intermediate vaporizes in which vaporization takes place in heat exchange with intermediate fluid heated by an external source	BKBB	-LNG-RG-BOG
Cryogenic Transferring	Element (L2)	loading of liquefied gases (e.g. LNG, propane, ethane and butane). The facilities comprise loading arms, transfer pumps	BBCA	-LNG-CT
Cryogenic Storage	Element (L2)	Storage of LNG at -160 degrees celsius	BBD	-LNG-ST
Sub Sea Pipeline System	Element (L2)	Sub sea transportation system consisting of pipelines and compressors	BDA	-LNG-SSP

Table A.4: Port layout requirements for different types of terminals (PIANC, 2019c).

Terminal Type	**Location in the Port**	**Berth to Storage / Processing**	**Relation to City**
Containers	Inner port, calm water	Adjacent: road, rail, IWT	Away from airport flight path
General cargo	Inner port, calm water	Adjacent: road, rail, IWT	Outside city areas
Dry bulk	Inner or outer port	Can be remote; mind conveyor costs: road, rail, IWT	Recreational and public use areas outside
Liquid bulk	Exposed location or at SPM	Separate via pipeline: pipelines, tank farms	Away from flight paths, flammable areas, and exclusion zones
Cars (Ro-Ro)	Inner port, calm water, ramp connection	Adjacent: road, rail, IWT	Away from dusty port activities
Ferries	Inner port, calm water, ramp/linkspan connection	Adjacent: road, rail, public transport	Dusty port activities inside
Cruise	Inner port, calm water	Adjacent (if customs/immigration required): road, rail, public transport	Near recreation areas; away from dusty areas
Fishing	Inner port, calm water	Adjacent: road, rail	Away from dusty port activities
Marinas	Inner port, calm water	Adjacent: road, commercial waterfronts, prime real estate	Away from industrial/-dusty areas

Table A.5: Facilities per terminal type (by TU Delft – Ports and Waterways, licensed under CC BY-NC-SA 4.0).

Terminal Type	**Quayside Equipment**	**Storage / Onshore Facilities**	**Hinterland Connections**
Containers	STS cranes	Container stacks	Road, rail, IWT
General cargo	Harbour cranes	Open/closed storage or warehouse	Road, rail
Dry bulk	Ship loaders	Silos, stockyard	IWT, rail, road, conveyor
Liquid bulk	Loading arms, hoses	Tanks, truck loading	Pipeline, IWT, trucks, rail
Ro-Ro	Ramp, linkspan	Parking facilities	Road, train
Fruit	Harbour cranes	Cold storage, refrigerated warehouse, packaging	Road
Fishery	Forklifts	Cold storage, refrigerated warehouse, auction halls, packaging	Road
Cruise/ferries	Linkspan, walk bridges, catwalk	Passenger terminal building, parking	Road, train
Marinas	Pontoons, walk bridges	Shiplift, winter storage, supplies, parking	Road

B

Verification of The Model

B.0.1. Model Verification Based on a Fictive System

Model verification is essential to ensure the functionality of the system. First, the system is defined, followed by the application of various tests to confirm its operation.

Definition of Fictive System

In this section, we define the elements of the system. The system is a simplified offshore wind setup consisting of a limited number of components, designed to minimize complexity while still having enough elements to validate the system's operation. The system includes:

- 3 wind turbines (with different construction start years)
- Array cables (which become operational when the first turbine is active),
- An AC substation and AC export cable (operational when the first turbine is active),
- A HVDC substation and DC export cable (operational when the second turbine is completed).

The following tables present the financial and operational assumptions for each system component. The data presented is illustrative and does not reflect actual market values. It is intended solely for conceptual and modeling purposes.

Element	CAPEX	Start Year	Construction Time	Lifetime	Base Year	Escalation Rate	Insurance
Turbine1	-11M	2024	3	30	2022	2%	0.5%
Foundation1	-4M	2023	1	30	2022	2%	0.5%
Turbine2	-11M	2025	3	30	2022	2%	0.5%
Foundation2	-4M	2024	1	30	2022	2%	0.5%
Turbine3	-11M	2026	3	30	2022	2%	0.5%
Foundation3	-4M	2025	1	30	2022	2%	0.5%
InterArrayCables	-1.5M	2025	2	30	2022	2%	0.5%
AC Substation	-6M	2025	2	40	2022	2%	0.5%
HVDC Substation	-6M	2026	2	40	2022	2%	0.5%
AC Export Cable	-3M	2025	2	25	2022	2%	0.5%
DC Export Cable	-6M	2025	3	25	2022	2%	0.5%
Mainland	-5M	2024	3	30	2022	2%	0.5%

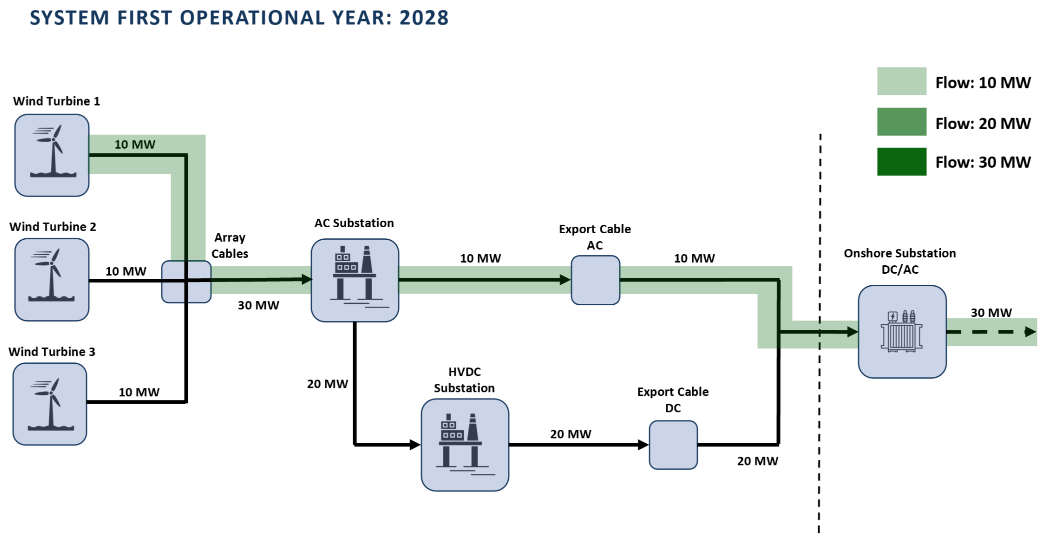
Element	Variable Cost Rate	Depreciation Rate	Decommissioning Rate	Downstream Neighbours
Turbine1	3%	3.33%	2%	InterArrayCables
Foundation1	3%	3.33%	2%	-

Turbine2	3%	3.33%	2%	InterArrayCables
Foundation2	3%	3.33%	2%	-
Turbine3	3%	3.33%	2%	InterArrayCables
Foundation3	3%	3.33%	2%	-
InterArrayCables	3%	3.33%	2%	AC Substation, HVDC Substation
AC Substation	3%	2.5%	2%	AC Export Cable
HVDC Substation	3%	2.5%	2%	HVDC Export Cable
AC Export Cable	3%	4%	2%	Mainland
DC Export Cable	3%	4%	2%	Mainland
Mainland	1.5%	3.33%	2%	-

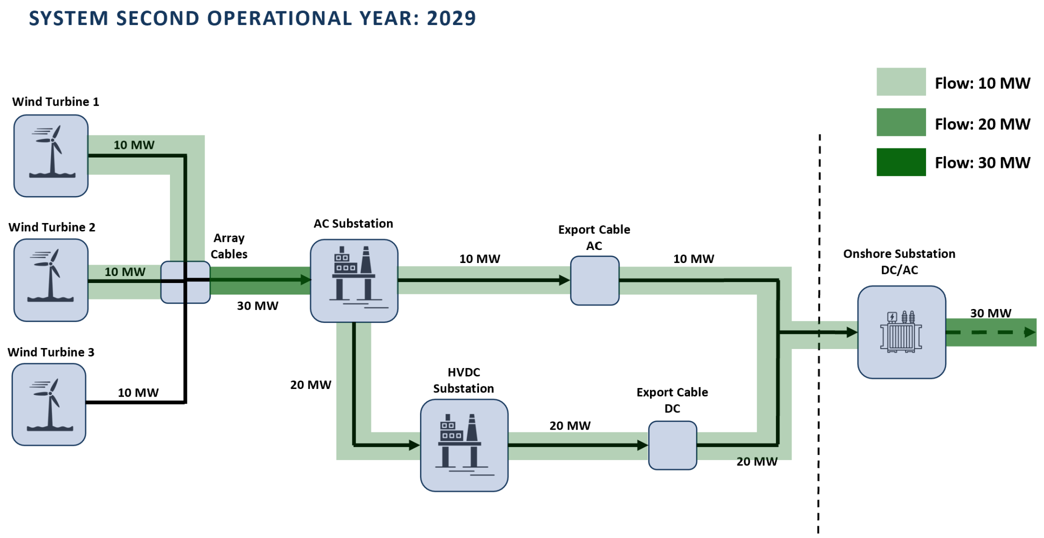
Capacity Test

The capacity test is performed using the fictive system. The installed capacity is illustrated in Figures B.2. In 2028, only 10 MW is active, with the AC substation and Turbine 1 operational. In 2029, the capacity increases to 20 MW, with two turbines, the AC substation, and the HVDC substation active. By 2030, all 30 MW are active, with three turbines and both substations operational.

An additional scenario is considered where the HVDC substation is delayed by two years. In this case, the system will only have 10 MW active from 2028 to 2030, even though all turbines are completed by 2030. In 2031, when the HVDC substation becomes operational, the system reaches full capacity of 30 MW. Both scenarios, "with and without delay," are incorporated into the model and visualized in Figure B.3. The model output matches the expected system behavior, confirming the model's correct functioning.

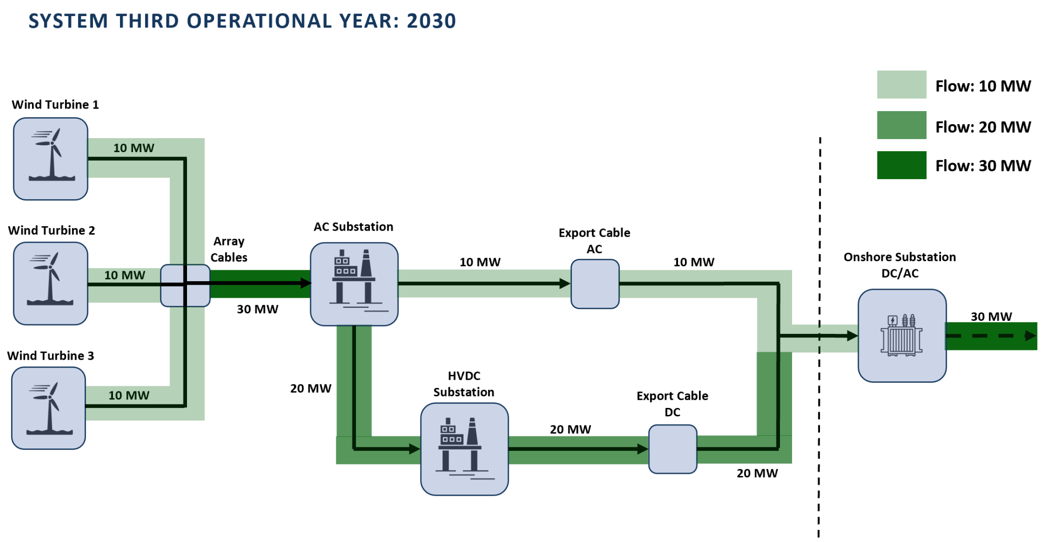


(a) System Installed Capacity Flow 2028

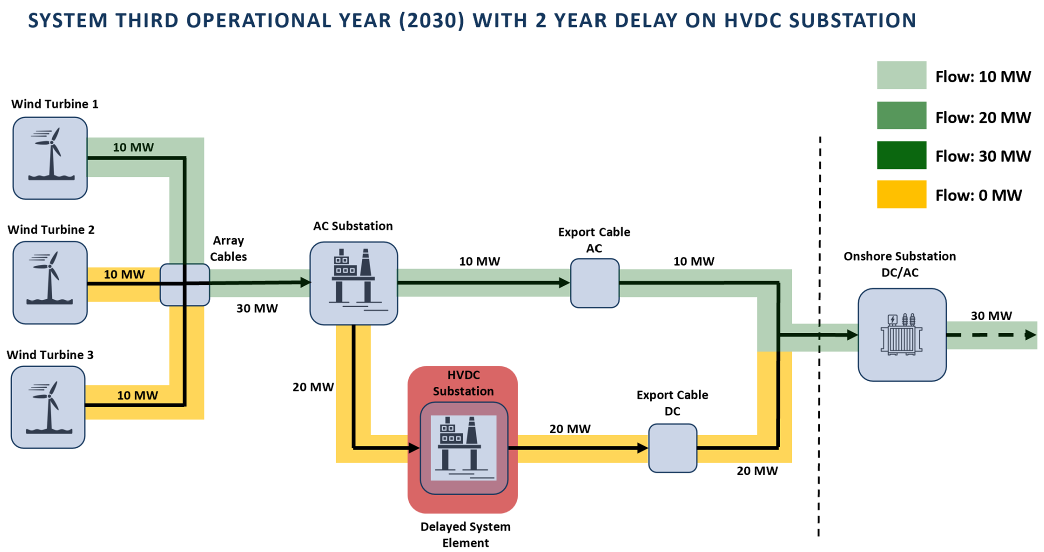


(b) System Installed Capacity Flow 2029

Figure B.1: Overview of Installed Capacity Flow



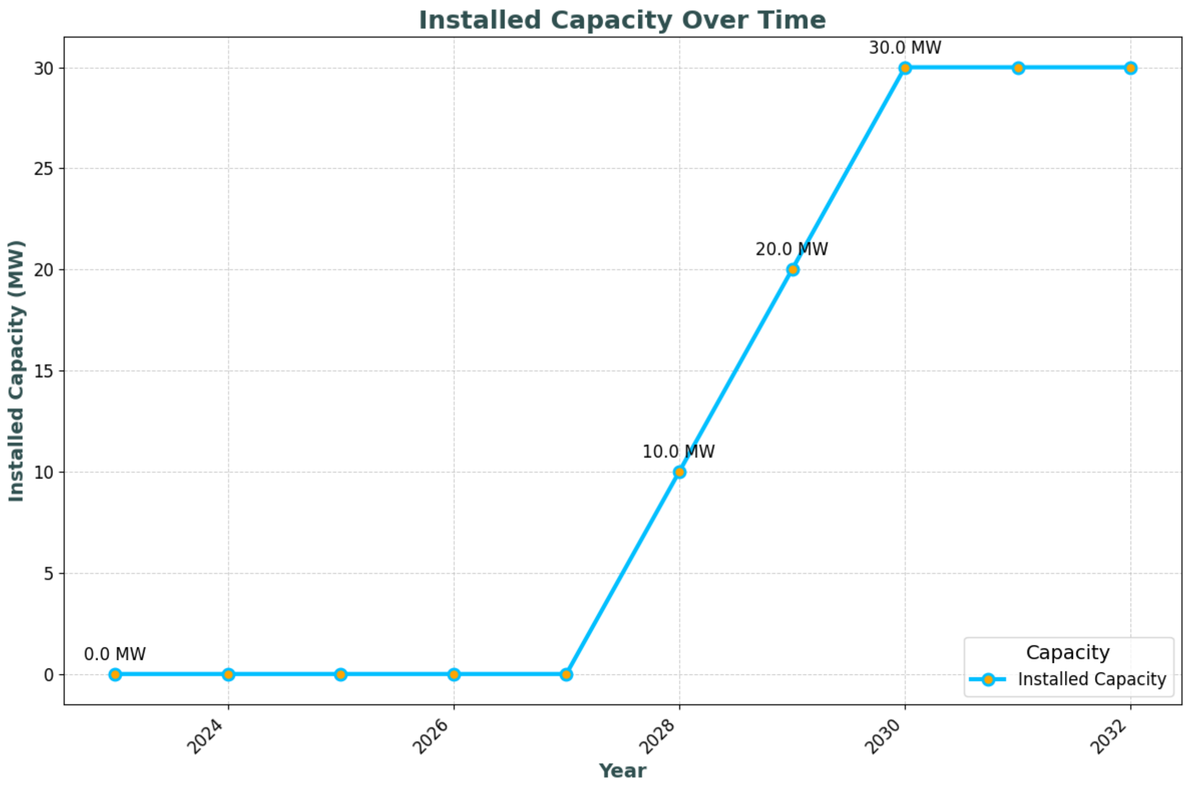
(a) System Installed Capacity Flow 2030



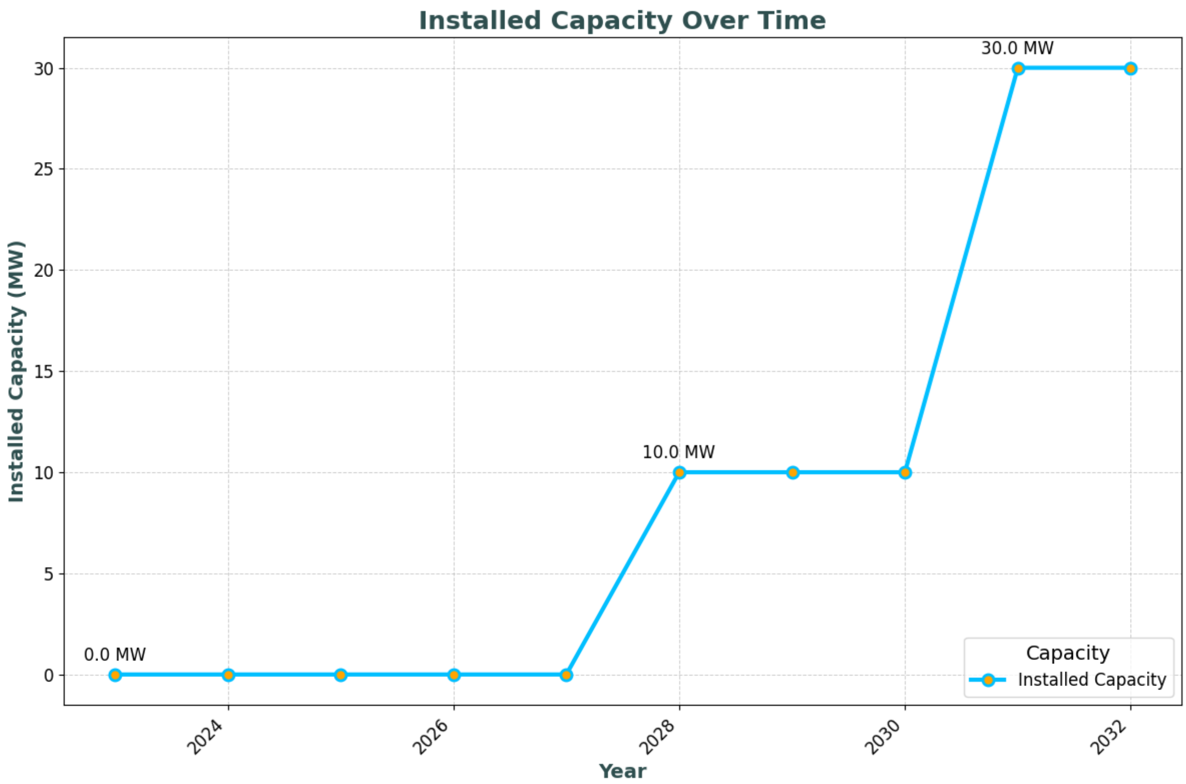
(b) System Installed Capacity Flow 2030, Delayed HVDC System Element

Figure B.2: Overview of Installed Capacity Flow

Figures from the model output:



(a) Model Output: Installed Capacity Normal Case



(b) Model Output: Installed Capacity Delayed Case

Figure B.3: Model Output Installed Capacity

Cashflow Modeling Test

For the cashflow test, the output from the model is compared to the results from the MTBS model to validate the model's accuracy. The goal is to align the model with industry standards and practices, as represented by the MTBS model.

The NPV values are compared, as this encompasses the cumulative effect of all cashflow elements. If any element is miscalculated, the NPV values would not match. Figures B.5 illustrate the comparison between the model outputs. Figure B.5b shows the output from the Python model, which, when compared to B.5a, shows that the free cash flow (FCF) projections align well. More importantly, the NPV values calculated by the Python model are also shown in B.5a, confirming that the Python model correctly follows the MTBS model, indicating that the model operates accurately according to industry standards.

years	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Escalated Capex	0	-4080000	-8531280	-22338428,4	-27764384,9	-15677947,41	-4955114,645	0	0	0	0
Escalated Opex	0	0	-148569,12	-306111,8148	-473050,0446	-1605617,896	-2624538,743	-3167293,997	-3230639,877	-3295252,675	-3361157,728
Escalated Revenue	0	0	0	0	0	0	2208161,606	4504649,677	6892114,006	7029956,286	7170555,412
Tax	0	0	0	0	0	0	0	0	-46328,95861	-49990,43274	-53725,13635
FCF	**0**	-4080000	-8679849	-22644540	-28237435	-17283565	-5371492	1337356	3615145	3684713	3755673
NPV MTBS	**0**	-3813084	-11394400	-29879091	-51421295	-63744238	-67323489	-66490652	-64386604	-62382364	-60473171
NPV Model	0	-3813084	-11394400	-29879091	-51421295	-63744238	-67323489	-66490652	-64386604	-62382364	-60473171
Difference Models	0	0	0	0	0	0	0	0	0	0	0

(a) FCF Projections and NPV Calculations 1

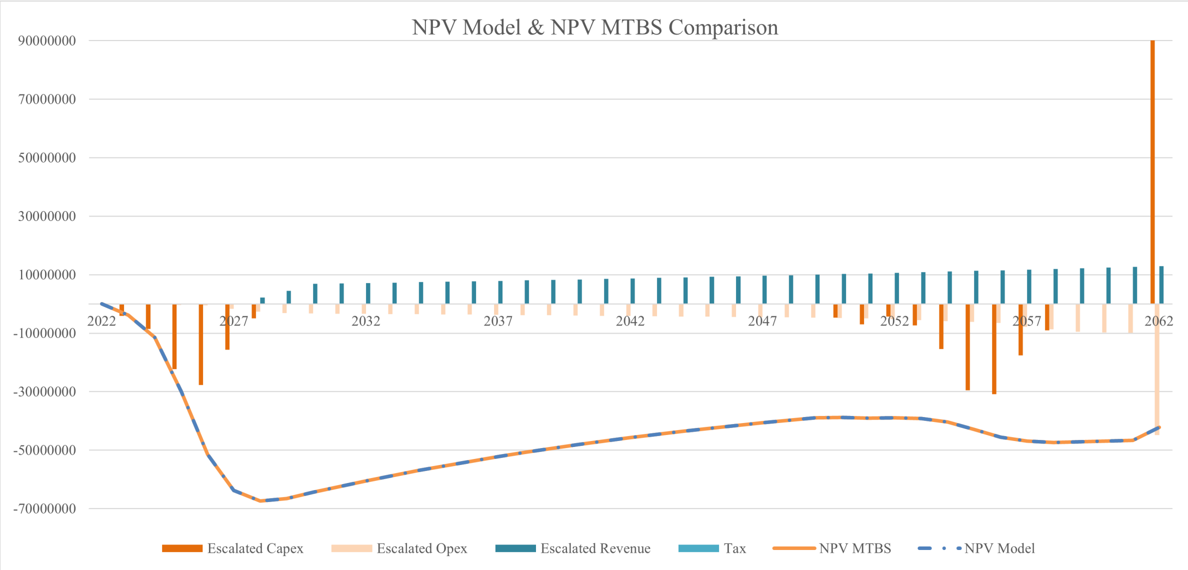
2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
0	0	0	0	0	0	0	0	0	0	0	0	0	0
-3638225,22	-3710989,724	-3785209,519	-3860913,709	-3938131,983	-4016894,623	-4097232,515	-4179177,165	-4262760,709	-4348015,923	-4434976,241	-4523675,766	-4614149,282	-4706432,267
7761639,783	7916872,578	8075210,03	8236714,231	8401448,515	8569477,485	8740867,035	8915684,376	9093998,063	9275878,025	9461395,585	9650623,497	9843635,967	10040508,69
-69425,98032	-73549,39488	-77755,27773	-82045,27825	-86421,07877	-90884,3953	-95436,97816	-100080,6127	-104817,1199	-109648,3572	-114576,2193	-119602,6387	-124729,5864	-129959,0731
4053989	4132333	4212245	4293755	4376895	4461698	4548198	4636427	4726420	4818214	4911843	5007345	5104757	5204117
-53699416	-52201668	-50774835	-49415542	-48120577	-46886880	-45711539	-44591782	-43524966	-42508579	-41540226	-40617627	-39738611	-38901110
-53699416	-52201668	-50774835	-49415542	-48120577	-46886880	-45711539	-44591782	-43524966	-42508579	-41540226	-40617627	-39738611	-38901110
0	0	0	0	0	0	0	0	0	0	0	0	0	0

(b) FCF Projections and NPV Calculations 2

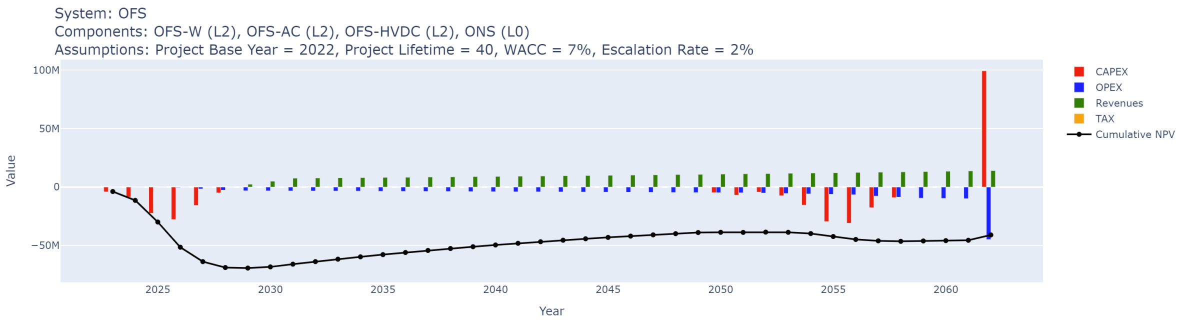
2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062
0	-4700765,357	-6925794,292	-4347267,802	-7390355,263	-15453232,86	-29506252,05	-30880647,5	-17599028,06	-8975504,312	0	0	0	99376871,21
-4706432,267	-4800560,913	-4896572,131	-5125092,797	-5497731,572	-5826033,664	-6169723,035	-6529463,809	-7762809,699	-8610613,574	-9503352,452	-9693419,501	-9887287,891	-44795356,73
10040508,69	10241318,86	10446145,24	10655068,14	10868169,5	11085532,89	11307243,55	11533388,42	11764056,19	11999337,32	12239324,06	12484110,54	12733792,75	12988468,61
-129959,0731	-135293,1495	-140733,9075	-135634,3332	-119302,5758	-108238,3819	-96511,84233	-84091,89116	-1525,174972	0	0	0	0	0
5204117	604699	-1516955	1047073	-2139220	-10301972	-24465243	-25960815	-13599307	-5586781	2735972	2790691	2846505	67569983
-38901110	-38810162	-39023389	-38885838	-39148477	-40330537	-42954060	-45555836	-46829587	-47318628	-47094801	-46881434	-46678037	-42165688
-38901110	-38810162	-39023389	-38885838	-39148477	-40330537	-42954060	-45555836	-46829587	-47318628	-47094801	-46881434	-46678037	-42165688
0	0	0	0	0	0	0	0	0	0	0	0	0	0

(c) FCF Projections and NPV Calculations 3

Figure B.4: Comparison of Free Cash Flow Model Outputs



(a) MTBS Model: FCF Projections and NPV Calculations



(b) Python Model: FCF Projections and NPV Calculations

Figure B.5: Comparison of Free Cash Flow Model Outputs

C

Base Case Offshore Wind Energy System

C.1. Overview System Elements and Components

The artificial island, visualized in figure C.1, serves as the central hub for both AC and HVDC substations.

The timeline visualized in figure C.2 in appendix C, outlines the phased development of the Princess Elisabeth Zoned offshore wind project, spanning from 2024 to 2030. It is organized into three tenders, each comprising multiple interconnected projects (FPS Economy, 2024).

Table C.1 provides an overview of all elements in the Princess Elisabeth Zone (PEZ) supply chain along with their characteristics. Cost data is derived from reports by Febeliec (2025) and PwC (2023).

Figure C.3 shows the physical characteristics of the Artificial Island.

Figure C.4 gives an overview of the locations of the elements of the PEZ system.

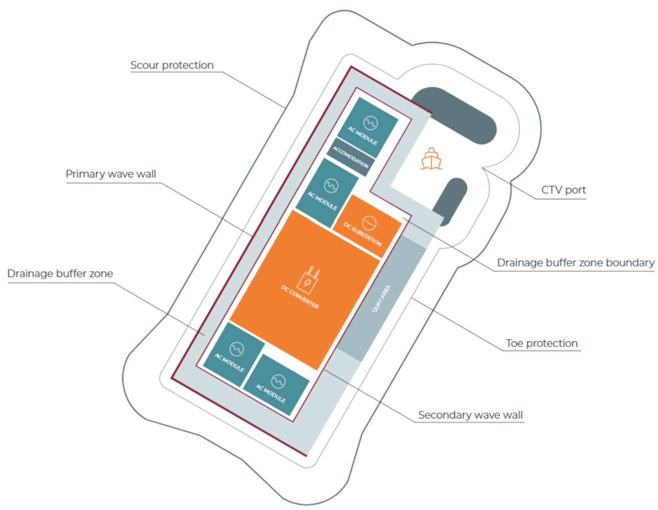


Figure C.1: Overview Artificial Offshore Island (Elia, 2022)

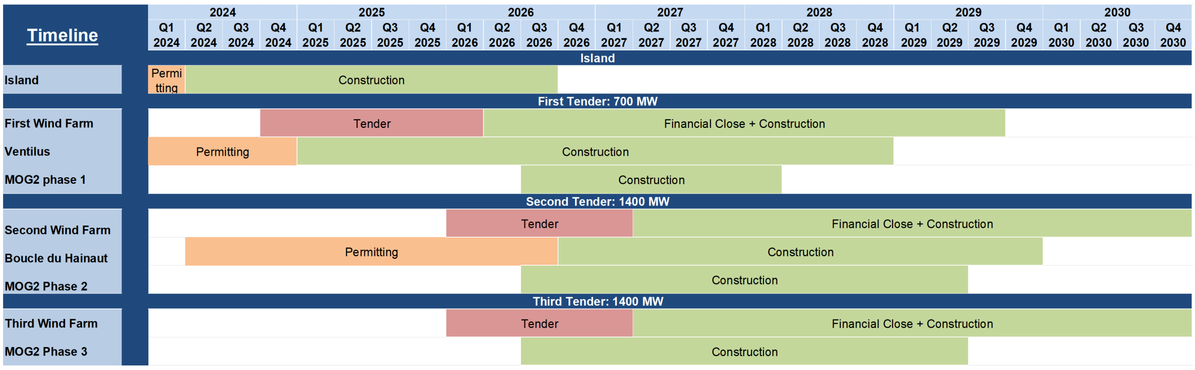


Figure C.2: Timeline MOG2 Project, (FPS Economy, 2024)

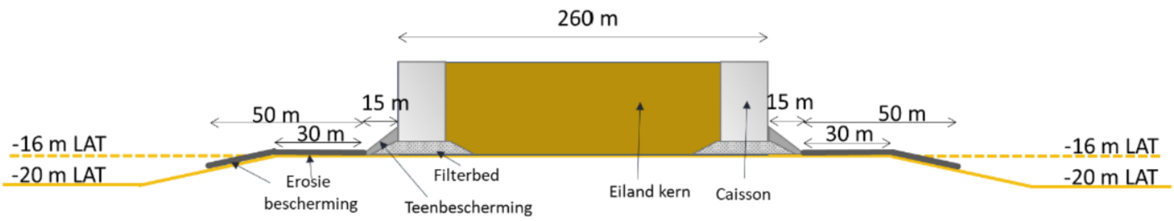


Figure C.3: Dimensions Artificial Island (Boerema et al., 2023)

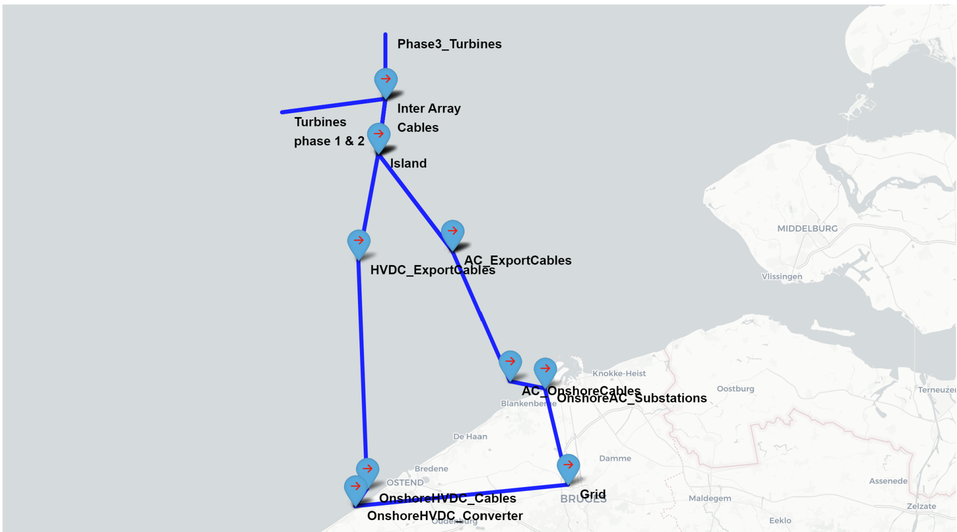


Figure C.4: Overview of PEZ elements location

C.2. Overview Uncertainty Modeling Process

A sensitivity analysis is conducted to assess the robustness of the LCOE in response to various uncertainties and scenario changes.

Uncertainties and Definition of Distributions

Multiple scenarios and distributions are defined, with the distribution values derived from literature sources.

1. WACC: To account for different perspectives on the WACC, multiple scenarios are used. While the base case assumes a WACC of 7%, studies such as those by Febeliec suggest lower values (e.g., 3.5%) when taking a societal perspective rather than an investor's. In this study, multiple scenarios for WACC within a range of 3.5% to 10% are considered. Rather than treating WACC as a source of probabilistic uncertainty, it is assessed through sensitivity analysis to understand how changes in the cost of capital influence the LCOE.

2. Delays: Another source of uncertainty in the LCOE calculation is the timeline for system deployment. The energy system consists of multiple elements that are tendered and constructed in different phases, each with its own probability of delay. These delays impact the timeline for when the system becomes fully operational, which in turn affects the total energy output and thus the LCOE.

Instead of assuming a deterministic installation path, we define a distribution for the installed capacity over time by accounting for delays in construction. We model the delay D (in years) as a discrete random variable following a Poisson distribution, reflecting that while most elements are expected to be completed on time, some delays are likely, and significant delays are rarer. Early completion is possible but occurs with very low probability (Alkaissy et al., 2022).

The probability mass function (PMF) for the discrete delay D is given by the Poisson distribution:

$$P(D = k) = \frac{\lambda^k e^{-\lambda}}{k!}, \quad k \geq -1 \tag{C.1}$$

where (Muralidhar et al., 2018):

- $\lambda = 3$ controls the average delay rate, determining the expected number of delays in construction.
- The shift of -1 is applied to the delay values so that the delays start from -1, allowing for the possibility of early completion, although rare.
- The probabilities are normalized to ensure they sum to 1.

The impact of different WACC scenarios and the uncertainty associated with system delays are modeled within an integrated simulation framework. The methodology is illustrated in figure C.5.

LCOE Distributions

The impact of different WACC scenarios and the uncertainty associated with system delays are modeled within an integrated simulation framework.

The process begins with the definition of delay distributions for individual system components. Using Monte Carlo sampling, 10,000 simulations are performed to assess the aggregate impact of these delays on the system's performance. For each simulation, delays are independently sampled for each component, after which the corresponding LCOE is calculated under three distinct WACC scenarios.

The resulting data is visualized in a scatter plot, in figure C.6, where each point represents the LCOE value corresponding to a specific average system delay. A regression line is included for each WACC scenario to illustrate the overall trend.

It is noteworthy that some simulations exhibit identical average system delays but yield different LCOE values. This is attributed to the structure of the system, which consists of multiple interdependent elements. Since the delays are sampled individually for each element, the configuration of critical path components can vary between simulations. In certain cases, delays in a single critical component can disproportionately affect the system's overall performance, explaining the observed divergence in LCOE despite similar average delays.

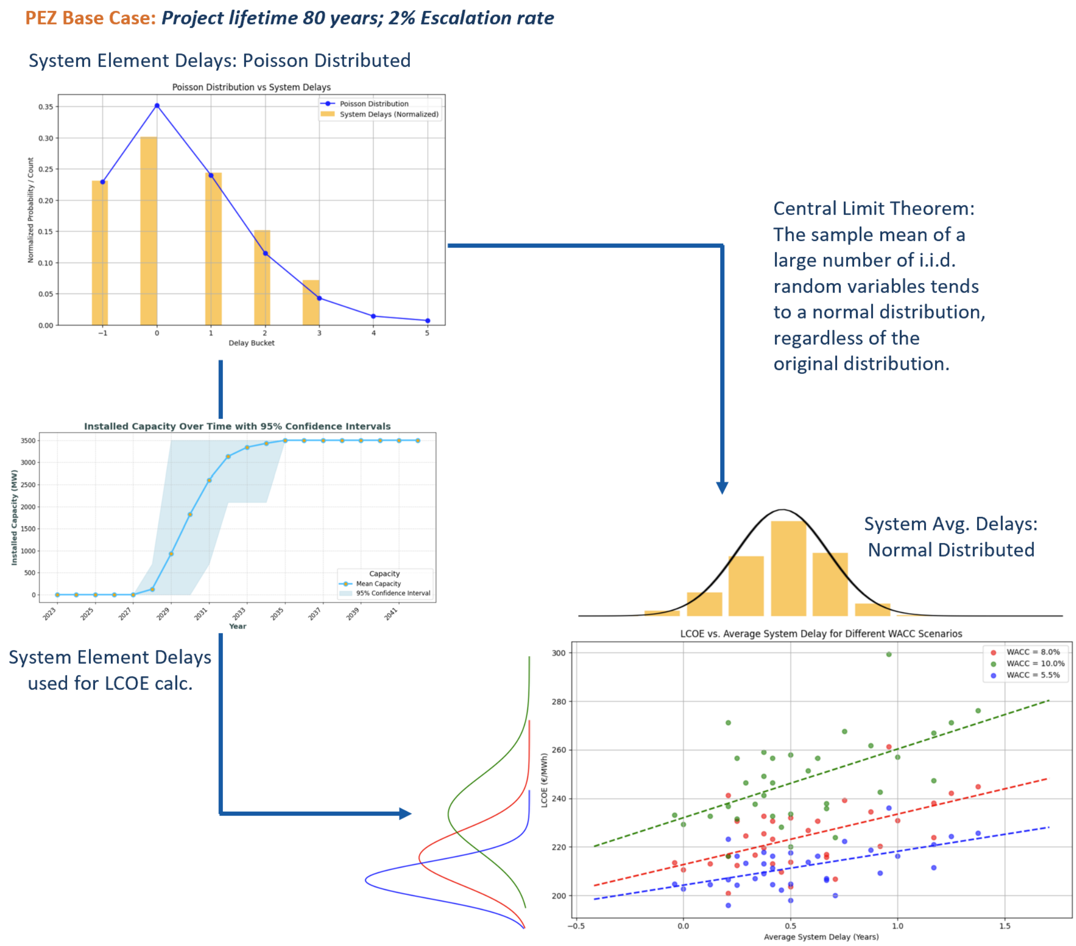


Figure C.5: Uncertainty and Scenario modeling methodology of LCOE

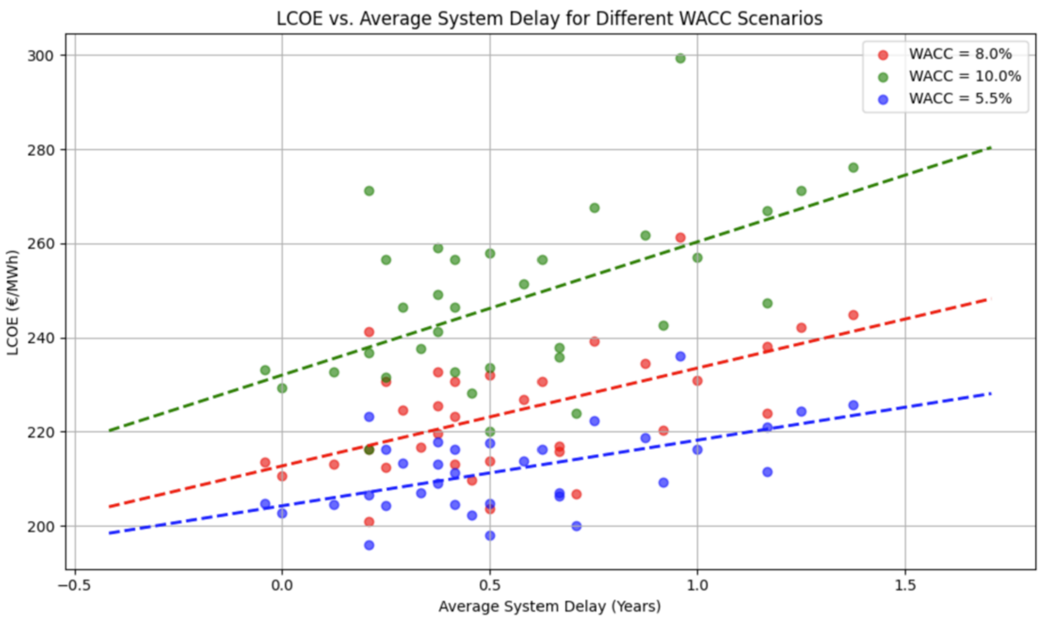


Figure C.6: Scatter plot of LCOE under element delay uncertainty for three WACC scenarios

C.3. Enhanced Base Case: Only AC equipment

The financial assumptions and physical breakdown of the system elements are outlined in Table C.2.

Figure C.7 illustrates the FCF of the PEZ base case with only AC equipment, over time.

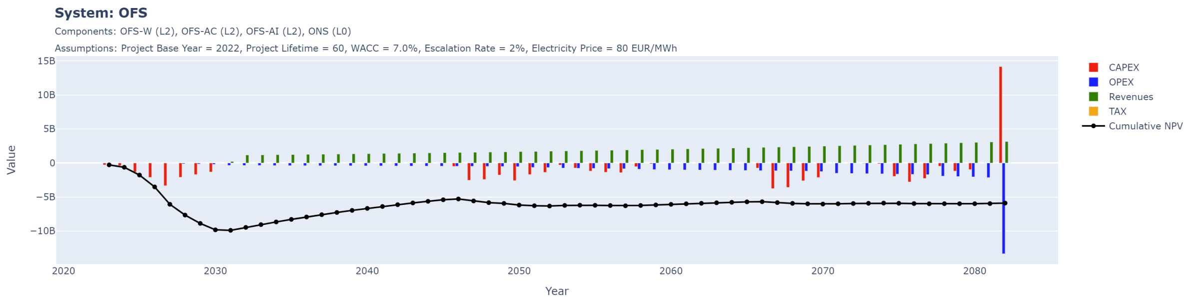


Figure C.7: Free Cash Flow of PEZ Base Case with AC Equipment Only

Figure C.8 provides a sunburst chart depicting the cost distribution across various components of the PEZ when only AC equipment is considered, over the project's full lifespan.

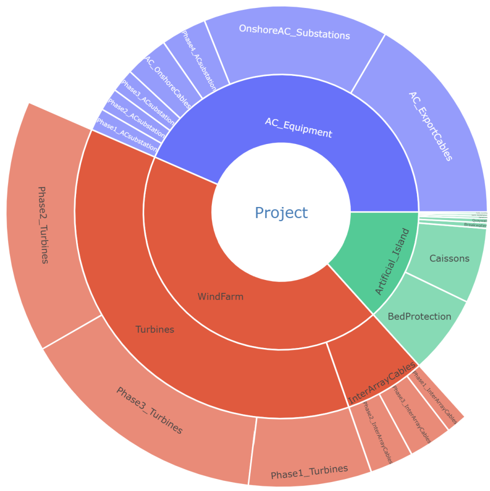


Figure C.8: Cost Distribution for PEZ Base Case with AC Equipment Only

C.4. Enhanced Base Case: HVDC as an Interconnector

Additional CAPEX and Revenues from Interconnector

Extra Costs for HVDC Cables: The estimated length of HVDC cables required to connect the island to both Denmark and the UK is approximately 700 km (Jorens, 2021). Using the cost per kilometer detailed in Table C.1, the total CAPEX for the cables is:

$$700 \times 4.05\,€\ \text{million/km} = 2,835\,€\ \text{million}$$

Arbitrage Benefits: If the interconnector operates at a high capacity, the available energy for arbitrage can be estimated based on an 85% capacity factor (CRE, 2016):

$$E_{\text{min}} = 1.4\,\text{GW} \times (0.85 \times 8,760\,\text{h}) = 1.4 \times 7,446 = 10.42\,\text{TWh/year} \tag{C.2}$$

With a €25/MWh price spread (European Commission, 2025) between the connected markets, the estimated annual revenue from arbitrage is:

$$\text{Revenue} = 10.42 \times 10^6\,\text{MWh/year} \times 25\,€\,/\text{MWh} = €\,260.5\,\text{million/year} \tag{C.3}$$

The interconnector could potentially enable up to 11.65 TWh/year of arbitrage transfers, generating up to €260.5 million/year in additional revenues. These revenues, alongside the capital costs, will be factored into the free cash flow of the PEZ system, resulting in a revised LCOE.

Table C.3 provides an overview of all elements in the Princess Elisabeth Zone (PEZ) supply chain for the second enhanced base case, along with their characteristics. Cost data is derived from reports by Febeliec (2025) and PwC (2023).

Cashflow and CAPEX overview

Figure C.9 displays the free cash flow over time for the base case with HVDC as an interconnector.

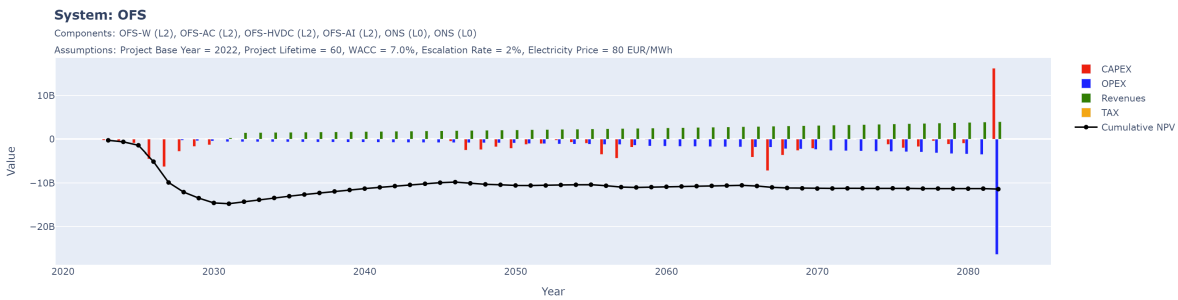


Figure C.9: Free Cash Flow of PEZ Base Case with HVDC Interconnector

Figure C.10 shows the cost distribution of various components of the PEZ with the HVDC interconnector over its lifetime.

Figure C.10: Cost Distribution for PEZ Base Case with HVDC Interconnector

Component	Element Name	Capacity/Dimension	Unit Cost []	CAPEX [EUR m]	OPEX [%]	Insurance rate [%]	Lifetime [years]	Decom. rate [%]]
AC Equipment		**2.1 GW**		**2750**				
	Offshore AC Substation Phase 1	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 1 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 2 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	AC Export Cables	330 km	4.05 [EUR m/km]	1340	2	0.5	25	2
	Onshore AC Cables	40 km	4.05 [EUR m/km]	162	2	0.5	25	2
	Onshore AC Substation (X3)	2.1 GW	208 [EUR m/asset]	624	2	0.5	30	2
HVDC Equipment		**1.4 GW**		**4160**				
	HVDC Converter Station	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
	HVDC Export Cables	55 km	4.05 [EUR m/km]	223	2	0.5	25	2
	Onshore HVDC Cables	10 km	4.05 [EUR m/km]	40.5	2	0.5	25	2
	Onshore HVDC Converter	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
Offshore Wind Farms		**3.5 GW**		**5864**				
	Windturbines Phase 1	700 MW	1.5 [EUR m/MW]	1050	2	0.5	20	2
	Windturbines Phase 2	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Windturbines Phase 3	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Array Cables Phase 1	130 km	1.2 [EUR m/km]	156	2	0.5	25	2
	Array Cables Phase 2	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
	Array Cables Phase 3	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
Artificial Island		**25 ha**		**920.5**				
	Island Caissons	23	16.5 [EUR m/unit]	380	1	0.5	80	1
	Island Sand Core	210m x 220m x 30m	8.3 [EUR/m^3]	11.5	1	0.5	80	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400	1	0.5	80	1
	Breakwater	320m	0.150 [EUR k/m]	48	1	0.5	50	1
	Quaywall	300m	0.125 [EUR m/m]	38	1	0.5	50	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23	2.5	0.5	25	1
	Cable Landing Facilities	1	20 [EUR m/unit]	20	2	0.5	30	2

Table C.1: System Elements and Associated Costs Base Case (Febeliec, 2025, PWC, 2023)

Component	Element Name	Capacity/Dimension	Unit Cost []	CAPEX [EUR m]	OPEX [%]	Insurance rate [%]	Lifetime [years]	Decom. rate [%]]
AC Equipment		**3.5 GW**		**2750**				
	Offshore AC Substation Phase 1	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 1 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 2 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 1 Phase 4	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 2 Phase 4	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	AC Export Cables	550 km	4.05 [EUR m/km]	2230	2	0.5	25	2
	Onshore AC Cables	67 km	4.05 [EUR m/km]	270	2	0.5	25	2
	Onshore AC Substation (X5)	3.5 GW	208 [EUR m/asset]	1040	2	0.5	30	2
Offshore Wind Farms		**3.5 GW**		**5864**				
	Windturbines Phase 1	700 MW	1.5 [EUR m/MW]	1050	2	0.5	20	2
	Windturbines Phase 2	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Windturbines Phase 3	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Array Cables Phase 1	130 km	1.2 [EUR m/km]	156	2	0.5	25	2
	Array Cables Phase 2	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
	Array Cables Phase 3	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
Artificial Island		**25 ha**		**920.5**				
	Island Caissons	23	16.5 [EUR m/unit]	380	1	0.5	80	1
	Island Sand Core	210m x 220m x 30m	8.3 [EUR/m^3]	11.5	1	0.5	80	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400	1	0.5	80	1
	Breakwater	320m	0.150 [EUR k/m]	48	1	0.5	50	1
	Quaywall	300m	0.125 [EUR m/m]	38	1	0.5	50	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23	2.5	0.5	25	1
	Cable Landing Facilities	1	20 [EUR m/unit]	20	2	0.5	30	2

Table C.2: System Elements and Associated Costs Base Case Enhanced (AC only) (Febeliec, 2025, PWC, 2023)

Component	Element Name	Capacity/Dimension	Unit Cost []	CAPEX [EUR m]	OPEX [%]	Insurance rate [%]	Lifetime [years]	Decom. rate [%]]
AC Equipment		**2.1 GW**		**2750**				
	Offshore AC Substation Phase 1	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 1 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 2 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	AC Export Cables	330 km	4.05 [EUR m/km]	1340	2	0.5	25	2
	Onshore AC Cables	40 km	4.05 [EUR m/km]	162	2	0.5	25	2
	Onshore AC Substation (X3)	2.1 GW	208 [EUR m/asset]	624	2	0.5	30	2
HVDC Equipment		**1.4 GW**		**4160**				
	HVDC Converter Station	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
	HVDC Export Cables	55 km	4.05 [EUR m/km]	223	2	0.5	25	2
	HVDC Interconnector Cables	700 km	4.05 [EUR m/km]	2835	2	0.5	25	2
	Onshore HVDC Cables	10 km	4.05 [EUR m/km]	40.5	2	0.5	25	2
	Onshore HVDC Converter	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
Offshore Wind Farms		**3.5 GW**		**5864**				
	Windturbines Phase 1	700 MW	1.5 [EUR m/MW]	1050	2	0.5	20	2
	Windturbines Phase 2	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Windturbines Phase 3	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Array Cables Phase 1	130 km	1.2 [EUR m/km]	156	2	0.5	25	2
	Array Cables Phase 2	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
	Array Cables Phase 3	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
Artificial Island		**25 ha**		**920.5**				
	Island Caissons	23	16.5 [EUR m/unit]	380	1	0.5	80	1
	Island Sand Core	210m x 220m x 30m	8.3 [EUR/m^3]	11.5	1	0.5	80	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400	1	0.5	80	1
	Breakwater	320m	0.150 [EUR k/m]	48	1	0.5	50	1
	Quaywall	300m	0.125 [EUR m/m]	38	1	0.5	50	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23	2.5	0.5	25	1
	Cable Landing Facilities	1	20 [EUR m/unit]	20	2	0.5	30	2

Table C.3: System Elements and Associated Costs Base Case Enhanced (HVDC interconnector)(Febeliec, 2025, PWC, 2023)

D

Port Function Selection: MCDA

The MCDA is conducted based on five main evaluation criteria: CAPEX & OPEX, Technical Feasibility, Revenue Potential, Environmental Impact, and Strategic Relevance. Weights were assigned to each criterion based on an expert-informed approach. The values for the criterion are based on expert discussions with the MTBS team.

Criterion	Weight
CAPEX & OPEX	20%
Technical Feasibility	20%
Revenue Potential	25%
Environmental Impact	15%
Strategic Relevance	20%

Table D.1: Criteria weights for MCDA

LNG Handling Terminal

An LNG import terminal is a specialized facility designed to receive, store, and regasify LNG delivered by large carriers. These terminals consist primarily of cryogenic storage tanks and regasification units, which convert the LNG back into its gaseous state for distribution into the natural gas grid. Due to the hazardous nature of cryogenic infrastructure and the risk profile associated with LNG, such facilities must be located at a safe distance from residential or densely populated areas (Sooby, 2020). A notable example is the Fluxys LNG terminal in Zeebrugge, which has played a strategic role in Belgium's energy supply chain and serves as a benchmark for future development.

Financially, typical CAPEX for a 7 mtpa LNG terminal are in the range of €500–750 million, while OPEX are approximately €20–35 million per year (Sooby, 2020). These values reflect the high complexity of such infrastructure, which includes extensive safety systems, cryogenic pipelines, and secure marine offloading facilities.

From a logistical standpoint, large LNG carriers generally require a draft of 12–15 meters, which imposes significant dredging requirements in traditional port environments. However, locating an LNG terminal on an offshore artificial island circumvents this issue due to naturally deeper waters, improving accessibility and reducing maintenance costs. Beyond technical aspects, LNG import terminals hold very high strategic value, contributing to national energy resilience and diversification (Danish Maritime Authority, 2012). A common spatial requirement is approximately 3 hectares per bcm of annual regasification capacity (Sooby, 2020).

CCS Terminal

A CCS terminal designed for offshore CO transport shares many technical and spatial similarities with LNG terminals. These facilities are responsible for receiving, storing, and transferring liquefied CO (LCO) for subsequent shipping and injection into subsea storage sites. Like LNG, CO must be handled at low temperatures and high pressures, necessitating cryogenic tanks, vapor handling systems, and high-integrity pipelines (Yoo, 2015; Yoo et al., 2013).

The infrastructure requirements are similarly capital-intensive, with CAPEX estimated at €500–750 million and annual OPEX in the range of €20–35 million. This reflects the complexity of LCO handling systems and the need for robust safety protocols. From a market perspective, future demand is expected to support terminals with capacities of around 7 mtpa (DNV, 2024a). Vessel draft requirements are also in the 12–15 meter range, which, again, makes offshore islands a preferable location due to their natural depth. Strategically, CCS terminals are critical assets in the transition to net-zero, enhancing energy system resilience and providing a pathway for industrial decarbonization. As with LNG terminals, the estimated footprint is approximately 3 hectares per bcm/year of storage and handling capacity (Yoo, 2015).

Naval Base

Naval infrastructure on artificial offshore islands can accommodate coast guard vessels, naval patrols, or hybrid military-logistical operations. These activities, while not directly revenue-generating like commercial terminals, can contribute significantly to national security, maritime surveillance, and geopolitical presence. The primary components include dedicated berths, logistics support systems, and high-security zones for personnel and sensitive equipment.

From a socioeconomic standpoint, naval operations can stimulate regional employment and indirectly support port-related economic ecosystems, particularly in areas with limited access to naval facilities (Jaffry et al., 2012). Their presence also enhances maritime law enforcement, emergency response capabilities, and contributes to broader maritime governance objectives (Asteris et al., 2018). While they are not core to commercial port operations, they hold medium strategic importance, especially in terms of sovereignty and resilience.

Capital investment for establishing naval infrastructure is typically in the range of €150–250 million, with operating expenditures around €5–10 million annually. These values reflect the moderate complexity of the systems involved, berthing infrastructure, maintenance, security, and support services (Asteris et al., 2018). Since naval deployment is mission-based rather than throughput-driven, conventional demand metrics like mtpa are not applicable. Draft requirements are somewhat lower than those for LNG or CCS vessels, generally between 6–9 meters, making them flexible in terms of siting. However, a naval zone still requires a significant spatial footprint, typically around 10–20 hectares (Jaffry et al., 2012).

Ship Bunkering & Maintenance

Bunkering and maintenance facilities are critical enablers for port efficiency and maritime decarbonization. These terminals provide fuels, conventionally oil-based, but increasingly alternative fuels like LNG, methanol, or ammonia, as well as maintenance berths and repair services for vessels. As shipping transitions toward greener fuels, the design and operation of bunkering infrastructure must adapt accordingly (De et al., 2019).

Modern bunkering terminals integrate storage tanks, fuel distribution pipelines, and emissions control systems. Their complexity is moderate, requiring docking infrastructure and robust safety protocols. Additionally, these terminals can be co-located with service and maintenance areas, improving port turnaround times and supporting vessel availability (Artana et al., 2024). Offshore placement may offer logistical advantages, such as deeper drafts and reduced land-use conflicts, while also allowing for direct fueling of vessels in transit or at anchor.

From an economic standpoint, capital expenditure is estimated at €150–200 million, with annual operating costs between €10–15 million. Capacity-wise, these facilities typically support 5–10 million tonnes of fuel throughput per year. Draft requirements range from 9 to 11 meters depending on ship class, which is compatible with deepwater offshore settings. In terms of space needs, bunkering and maintenance zones require approximately 1.5 hectares per million tonnes of fuel capacity annually (De et al., 2019). Their strategic value is high, especially as ports seek to become hubs for green maritime fuels and decarbonization support infrastructure (Artana et al., 2024).

Table D.2 gives an overview of the key aspects of each functionalty.

Functionality	CAPEX	OPEX	Technical Complexity	Potential Throughput	Required Draft	Strategic Alignment	Required Space / Capacity Unit
LNG Handling	€500–750M	€20–35M/yr	High (cryogenic tanks, pipelines)	11.3 mtpa	12–15 m	Very High – Energy resilience and diversification	$\tilde{3}$ ha per bcm/year
CCS Terminal	€400–700M	€15–25M/yr	High (compression, storage, pipelines to reservoir)	2–10 $MtCO_2$/yr	11–14 m	Very High – EU Green Deal, ETS incentives	$\tilde{2}$.5 ha per Mt/year
Naval Activities	€150–250M	€5–10M/yr	Medium (berths, logistics, security)	N/A (mission-based)	6–9 m	Medium – Strategic, not core to port ops	10–20 ha
Ship Bunkering/Maint.	€150–200M	€10–15M/yr	Medium (docking, fuel infrastructure)	5–10 Mt/year	9–11 m	High – Green fuels, decarbonization support	$\tilde{1}$.5 ha per Mt/year

Table D.2: MCDA inputs for shortlisted offshore island functionalities including draft and spatial requirements

Each function is then scored on a scale from 1 (low) to 5 (high) for each criterion, based on the insights previously described. The weighted total score is calculated accordingly.

Functionality	CAPEX/OPEX	Tech. Feas.	Revenue	Env. Impact	Strategic	Total
LNG Handling	3	5	5	2	5	4.00
CCS Infrastructure	3	4	3	5	5	3.85
Ship Bunkering/Maint.	4	4	3	3	3	3.40
Naval Activities	4	3	2	4	4	3.25

Table D.3: MCDA scoring of remaining functionalities (weighted total out of 5)

E

Base Case(s) LNG Terminal

E.1. Base Case Onshore LNG Terminal – 9 bcm/y (6.6 mtpa)

E.1.1. Supply Chain Breakdown and Costs

In tables E.1, E.2 an overview is given of all components from the LNG system associated to the base case and their respective CAPEX and OPEX values. The physical and financial characteristics of the components were found in the report by Sooby, 2020, which was obtained through MTBS.

Cost Estimations

The capital expenditure includes both the LNG terminal and associated port infrastructure such as dredging and jetty development. Table E.2 presents the estimated financial characteristics (Sooby, 2020).

E.1.2. Estimated Revenue for a 6.6 mtpa LNG Terminal

The Zeebrugge LNG terminal generates revenue from three primary streams: regasification services, berthing fees, and transshipment operations. Based on publicly available tariffs from Fluxys[1], and observed vessel activity, we estimate annual revenue as follows:

Assumptions:

- Full utilization of regasification capacity (6.6 mtpa) (Fluxys, 2025).
- 13.5 MWh/tonne LNG energy conversion factor (Sooby, 2020).
- Fluxys published tariffs as of 2024.
- 94 unloading and 82 transshipment ship calls per year (Fluxys, 2024b)).
- All reloading operations include both cargo and berthing components.

1. Regasification Service: The terminal earns capacity-based revenue by offering firm send-out rights to shippers. According to Fluxys LNG tariffs, the firm regasification tariff is:

$$\text{Firm Regasification Tariff} = 135,695.71\,€ \text{ per MW per year}$$

With 1,025 MW of continuous send-out capacity, the annual regasification revenue is:

$$\text{Regasification Revenue} = 1,025 \times 135,695.71 = 139,000,000\,€ \;/\; \text{year}$$

Note: This figure represents the upper bound assuming full terminal utilization of regasification. Actual long-term capacity bookings and commercial contracts may vary. Yet the website of Fluxys states that the full regasification capacity has been booked up until 2042.

2. Berthing and Unloading Services: For each ship unloading LNG into the onshore terminal, a berthing and unloading tariff of €436,263 is applied. With 94 regas-related ship calls per year, the annual berthing and unloading revenue is:

[1] https://www.fluxys.com/en/natural-gas-and-biomethane/empowering-you/tariffs/tariff_fluxyslng-lng

$$\text{Berthing and Unloading Revenue} = 94 \times 436,263 = 41,000,000\,€ \ / \ \text{year}$$

3. Transshipment Operations: Transshipment is a significant part of Zeebrugge's business model. In 2020, the terminal handled 176 ship calls, with only 94 attributed to unloading for regasification. The remaining 82 ship calls are assumed to be for transshipment, involving reloading and berthing.

$$\text{Reloading Revenue} = 82 \times 151,680 = 12,423,360\,€ \tag{E.1}$$

$$\text{Berthing Revenue (Transshipment)} = 82 \times 126,845 = 10,405,290\,€ \tag{E.2}$$

$$\text{Total Transshipment Revenue} = 12,423,360 + 10,405,290 = 22,828,650\,€ \ / \ \text{year} \tag{E.3}$$

4. Total Estimated Annual Revenue: The total estimated annual revenue is the sum of regasification, berthing and unloading, and transshipment revenues:

$$\text{Total Revenue} = 139,000,000\,€\,\text{(regas)} + 41,000,000\,€\,\text{(berthing)} + 22,828,650\,€\,\text{(transshipment)} = 202,828,650\,€ \ / \ \text{year}$$

The value found from the calculation is in line with what Fluxys has reported as revenue in 2023, which was 217 € million (CompanyWeb, 2025).

E.2. Base Case Offshore LNG Terminal Princess Elisabeth Island – 9 bcm/y (6.6 mtpa)

Cost Estimations

The capital expenditure includes both the LNG terminal and associated island and port infrastructure such as caissons and jetty development. Table E.3 presents the estimated financial characteristics (Sooby, 2020).

E.3. LNG Terminal Financial Feasibility under Uncertainty

Probability Distributions & Scenarios

For each simulated year, the total annual revenue is perturbed by a multiplicative stochastic shock $X_t \sim \mathcal{N}(1, \sigma^2)$, where:

- $\mathcal{N}$ denotes the normal distribution;
- the mean is fixed at 1, so that the expected value of the shock does not bias the deterministic trend;
- σ is adjusted based on the scenario to represent different levels of volatility.

This formulation means that the annual revenue R_t in year t is given by:

$$R_t = R_{t,\text{deterministic}} \cdot X_t$$

In all scenarios, changes in revenue are modeled using deterministic trend and normal distributions centered around a mean of 1, with scenario-specific standard deviations (σ) reflecting different levels of market uncertainty. This is expressed as $R_t = R_{t,\text{deterministic}} \cdot X_t$, where $R_{t,\text{deterministic}}$ represents the scenario's trend component (e.g., stable growth, decline, or cycles), and $X_t \sim \mathcal{N}(1, \sigma^2)$ captures the proportional random variation around that trend. The normal distribution is widely used in financial and economic modeling due to its ability to capture symmetrical uncertainty around an expected value and its computational tractability in Monte Carlo simulations. While real-world processes can exhibit skewness or fat tails, using $\mathcal{N}(1, \sigma^2)$ provides a reasonable first-order approximation of log-normal behavior, commonly observed in prices and demand, thus offering a practical and intuitive way to incorporate volatility into revenue forecasts.

The scenarios and their corresponding assumptions are as follows:

- Stable Growth: Assumes a consistent annual growth of 1.5% with gradually increasing volatility. Although the terminal's regasification capacity is fully booked until 2040, there remains significant potential for growth through expanded transshipment and storage services. The standard deviation of market shocks starts at a base of $\sigma = 1\%$ and increases over time (e.g., proportionally to $\sqrt{t}$), representing a maturing but still evolving market environment. This scenario captures steady demand growth and policy support, while acknowledging that long-term projections become less certain over time (Yusuf et al., 2023).

- Geopolitical Shock and Recovery: Models an initial phase of disruption, typically associated with conflict, sanctions, or sudden supply constraints. In years 3–5, a significant spike in revenue (up to 40%) occurs due to market instability and price surges, accompanied by high volatility (σ = 10%). This reflects real-world phenomena where supply shortages or war-related disruptions increase prices sharply. After year 5, the scenario simulates a recovery phase where revenues gradually normalize, and volatility declines (σ = 5%). By year 20, the market is assumed to stabilize with moderate volatility (σ = 3%). The scenario highlights the short-term gains but long-term uncertainty associated with crisis-driven revenue surges (J. Zhang et al., 2024, Meza et al., 2021)).
- Green Transition: Captures a structural transformation of energy markets due to climate policy, technological shifts, and changing investor behavior. The first 20 years simulate a steady annual decline of 1% with low volatility (σ = 2%), indicating a controlled but persistent shift away from carbon-intensive energy systems. After year 20, the transition accelerates (decline of approximately 1.4% per year), and volatility increases (σ = 5%) to reflect uncertainties in policy execution, market adaptation, and potential stranded assets. This scenario emphasizes long-term revenue erosion in fossil fuel-linked activities and the importance of strategic repositioning (Steuer, 2019).
- Volatile Cycles: Revenue follows a sinusoidal 15-year boom-bust cycle around the baseline, simulating commodity price cycles, regulatory swings, or investment over-/under-capacity. Periods of expansion (booms) are followed by contractions (busts), with cycles shaped to resemble real-world asymmetry, where busts are often deeper and more volatile than booms. Volatility remains elevated throughout (σ = 8% to 12%), with higher values during downturns. This scenario reflects industries like LNG or shipping, where cyclicality is inherent, and strategic timing of investments is critical to mitigating risk and maximizing returns (Steuer, 2019, Hönig et al., 2019).
- Base Case: Assumes stable, flat revenues over time with moderate volatility (σ = 3%). It serves as a neutral reference point, assuming no major structural shifts or disruptions. The base case allows for comparison with other scenarios to understand the relative impact of growth, decline, and volatility on project feasibility.

Outputs and Interpretation:
For each scenario, the simulation produces a distribution of annual revenues across all 1,000 runs. The mean trajectory, along with the 2.5th and 97.5th percentiles, are plotted to illustrate the expected path and the 95% confidence interval. A comparative subplot of mean revenues across all scenarios is included to facilitate high-level evaluation of long-term financial resilience under varying assumptions. Figure E.1 displays the different revenue scenarios.

Table E.1: Key Components and Capacities of Case 1 (Sooby, 2020, Özelkan et al., 2008)

Component	**Element**	**Description**	**Unit / Capacity**
Marine Works			
	Breakwater	Protective measure within the port	1.5 km in 15 m water depth
	Jetty and Berths	2 LNG berths for Q-Max and Q-Flex LNGCs	Up to 266,000 m^3 LNGC
	Dredging	Access channel and turning basin, minimal water depth 17 m	8 million m^3
Terminal Area			
	Land Reclamation	Reclamed land area in 5 m water depth	2 million m^3 of sand
	Quay Wall	Earth retaining structure	1.1 km in 15 m water depth
Cryogenic Transfer			
	Unloading Arms	Cryogenic unloading systems (3–4 arms)	10,000–12,000 m^3/h
	LNG Pipelines	Cryogenic pipeline to tanks (1–2 km)	DN 800–1000
Storage			
	LNG Storage Tanks	5 full containment tanks	180,000 m^3 each
Regasification			
	Vaporizers	SCV or ORV for regasification	30–35 MWh/h total
	BOG Handling	Compression and reliquefaction system	Sized for 0.1–0.2% daily boil-off
Gas Export			
	Gas Export Compressor	Export to national gas grid	50–70 bar output
	Pipeline to Grid	Gas pipeline with metering	2–3 km, DN 800
Miscellaneous			
	Utilities	Nitrogen, firewater, diesel backup	N/A
	Control Systems	SCADA, central control, safety	Redundant system

Table E.2: Cost Breakdown and Technical Parameters of onshore LNG Terminal System (Sooby, 2020, Özelkan et al., 2008)

Component	**Element Name**	**Capacity/Dimension**	**Unit Cost []**	**CAPEX [EUR]**	**Lifetime [years]**	**OPEX [%]**	**Insurance rate [%]**	**Decom. rate [%]]**
Terminal Area								
	Land Reclamation	2 million m^3 sand	10 EUR/m^3	20,000,000	100	0.02	0.005	0.02
	Quaywalls	1.1 km in 15m depth	110,000 EUR/m	120,000,000	40	0.03	0.005	0.02
Marine Works								
	Breakwater	1.5 km in 15m depth	54,000 EUR/m	83,000,000	40	0.03	0.005	0.02
	Dredging	8 million m^3	7.5 EUR/m^3	60,000,000	100	0.10	0.005	0.02
	Jetty and Berths	2 units	35,000,000 EUR/asset	70,000,000	25	0.04	0.005	0.02
	Navigation Aids	-	3,000,000 EUR/asset	3,000,000	25	0.02	0.005	0.02
Cryogenic Transfer								
	Unloading Arms	4 units	3,000,000 EUR/asset	12,000,000	25	0.06	0.005	0.02
	LNG Pipeline	2 km	5,000 EUR/m	10,000,000	25	0.06	0.005	0.02
Storage								
	LNG Tanks	900,000 m^3	450 EUR/m^3	400,000,000	30	0.07	0.005	0.02
Regasification								
	Vaporizers	6.6 mtpa	17,000,000 EUR/mtpa	110,000,000	25	0.04	0.005	0.02
	BOG System	1% boil-off	15,000,000 EUR/asset	15,000,000	25	0.04	0.005	0.02
Miscellaneous								
	Utilities	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Control and Safety	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Land and Permitting	-	20,000,000 EUR/asset	20,000,000	40	0.02	0.005	0.02
Gas Export								
	Pipeline & Compressor	3 km	3,300 EUR/m	10,000,000	30	0.02	0.005	0.02

Table E.3: Cost Breakdown and Technical Parameters of offshore LNG Terminal System (Sooby, 2020, Özelkan et al., 2008)

Component	Element Name	Capacity/Dimension	Unit Cost []	CAPEX [EUR]	Lifetime [years]	OPEX [%]	Insurance rate [%]	Decom. rate [%]]
Artificial Island								
	Island Caissons	46	16.5 [EUR m/unit]	760,000,000	80	1	0.5	1
	Island Sand Core	430m x 430m x 30m	8.3 [EUR/m^3]	38,300,000	80	1	0.5	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400,000,000	80	1	0.5	1
	Quaywall	300m	0.125 [EUR m/m]	38,000,000	50	1	0.5	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23,000,000	25	2.5	0.5	1
Marine Works								
	Breakwater	1.5 km in 15m depth	54,000 EUR/m	83,000,000	40	0.03	0.005	0.02
	Jetty and Berths	2 units	35,000,000 EUR/asset	70,000,000	25	0.04	0.005	0.02
	Navigation Aids	-	3,000,000 EUR/asset	3,000,000	25	0.02	0.005	0.02
Cryogenic Transfer								
	Unloading Arms	4 units	3,000,000 EUR/asset	12,000,000	25	0.06	0.005	0.02
	LNG Pipeline	2 km	5,000 EUR/m	10,000,000	25	0.06	0.005	0.02
Storage								
	LNG Tanks	900,000 m^3	450 EUR/m^3	400,000,000	30	0.07	0.005	0.02
Regasification								
	Vaporizers	6.6 mtpa	17,000,000 EUR/mtpa	110,000,000	25	0.04	0.005	0.02
	BOG System	1% boil-off	15,000,000 EUR/asset	15,000,000	25	0.04	0.005	0.02
Miscellaneous								
	Utilities	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Control and Safety	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Land and Permitting	-	20,000,000 EUR/asset	20,000,000	40	0.02	0.005	0.02
Gas Export								
	Pipeline & Compressor	40 km	3,300 EUR/m	200,000,000	30	0.02	0.005	0.02

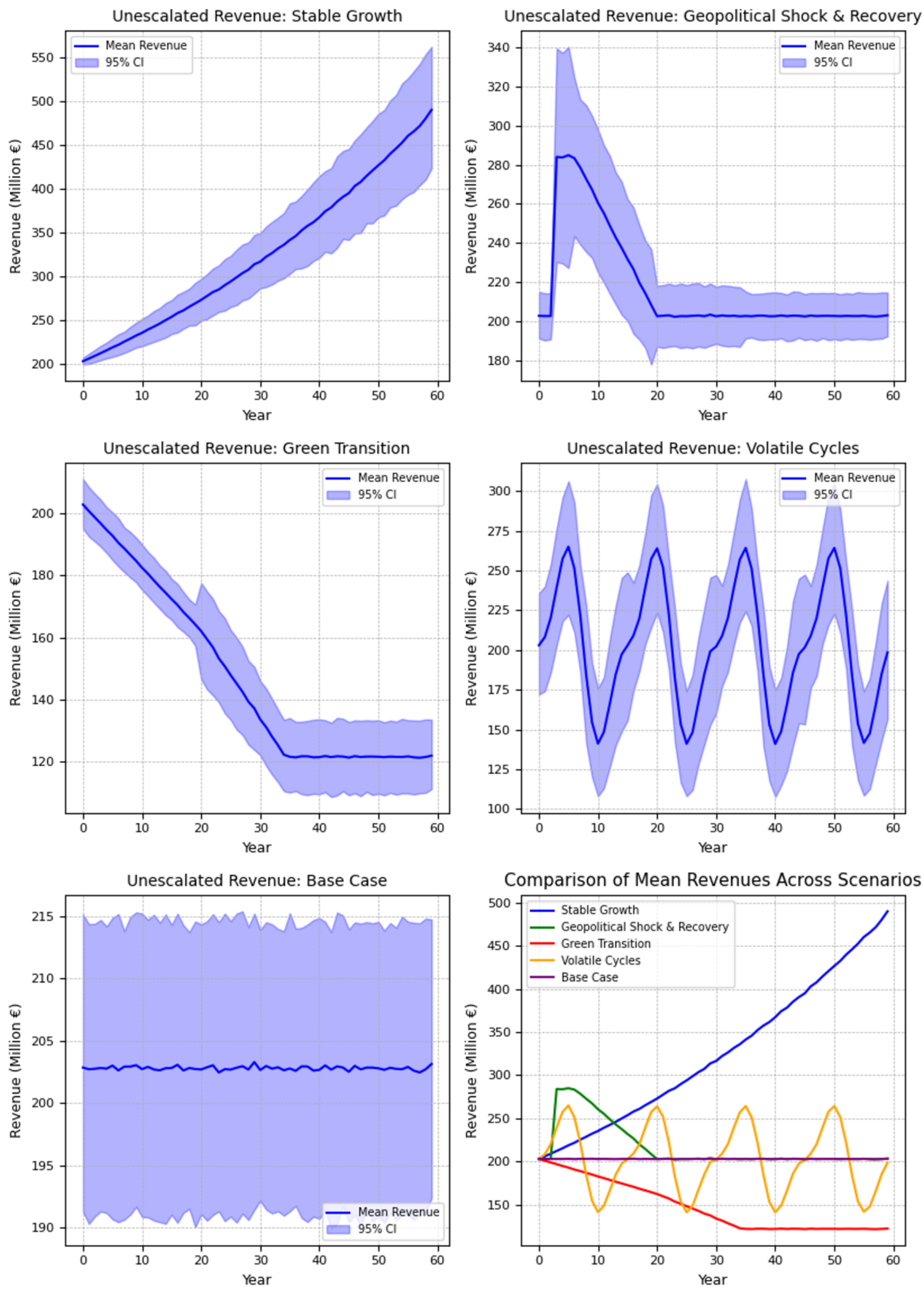


Figure E.1: Revenue Scenarios LNG Terminal

F

Multifunctional Island Design and Synergies

Synergies via Island Layout Optimization (Rectangular)

The total usable area of the island is estimated at 26 hectares (260,000 m^2), with the following infrastructure demands:

- 6.6 mtpa LNG Terminal: Approx. 20 ha
- HVDC (1.4 GW) + HVAC (2.1 GW): Approx. 6 ha

Since only the perimeter of the island requires costly caissons, the goal is to minimize this perimeter for a given area. While a circle is most efficient, practical constraints (berthing for LNG carriers, cable routing, phased construction, etc.) often favor rectangular layouts (Elia, 2023). We therefore assume a rectangular footprint and optimize dimensions accordingly.

Perimeter Minimization for Rectangular Island: Let:

- Area $A = 260{,}000\ \mathrm{m}^2$
- Dimensions $L \times W$
- Perimeter $P = 2L + 2W$

Perimeter of rectangle becomes minimal for a square layout:

$$L = W = \sqrt{260{,}000} \approx 510\ \mathrm{m}$$

$$P_{\mathrm{square}} = 4 \times 510 = 2{,}040\ \mathrm{m}$$

Infrastructure Layout within Square Island:

- Berthing and LNG Pipe Rack Zone (4 ha) placed along one full side for marine access (Sooby, 2020)
- LNG Storage Tanks (5 ha) placed directly behind berthing zone; arranged in 2×3 grid or L-shaped cluster (Sooby, 2020)
- LNG Regasification Units (3 ha) adjacent to tanks for minimal piping distance (Sooby, 2020)
- LNG Safety Buffer (8 ha) encircles LNG terminal, integrated with wider island zoning (Sooby, 2020)
- HVDC and HVAC Stations (6 ha) placed at the opposite end of the island for clear functional separation (Elia, 2023)

Advantages of Rectangular Optimization:

- Zoning: Simplified separation of high-risk (LNG) and sensitive (electrical) areas
- Construction Phasing: Allows modular build-out (e.g., one side first)
- Efficient Cable Routing: AC and HVDC infrastructure align well with straight runs to offshore wind farms and export cables

A rectangular layout offers a balance between construction simplicity, zoning logic, and moderate perimeter length (2,040 m), which still enables substantial cost savings on caissons compared to longer or irregular geometries.

The usable area of the island increases from 6 ha (in the energy island base case) to 26 ha, a 4 to 5-fold increase. However, the perimeter only doubles, from 1,000 m to 2,040 m. This results in the number of caissons increasing from 23 in the base case to 50 in the combined system. While the total cost doubles, the usable area increases by a factor of 5.

Electrical Energy Use of LNG Storage and Regasification

The LNG terminal, consisting of five storage tanks of 180,000 m^3 each (total capacity of 900,000 m^3), consumes electrical energy for both storage operations and regasification. The energy demand arises from boil-off gas (BOG) management, auxiliary systems (pumps, valves, sensors), vapour recovery units, and most significantly, the regasification process itself (Sooby, 2020).

Storage Operations: Based on literature values, the average electrical energy use for LNG storage is estimated at approximately 8–10 kWh per m^3 per year. This results in an annual storage-related energy use of approximately 7.7–9 GWh (Sooby, 2020).

Regasification: Assuming the use of electric vaporizers (which is expected for offshore applications to avoid combustion), the regasification process is significantly more electricity-intensive. Literature and industry sources indicate energy requirements in the range of 150–200 kWh per tonne of LNG. For a regasification capacity of 6.6 MTPA, this results in an annual electrical energy use of approximately 990–1320 GWh (Sooby, 2020).

Total Energy Use: Adding the storage energy demand, the total annual electrical energy consumption of the LNG terminal is approximately:

$$E_{\text{total}} = (7.7 \text{ to } 9)\ \text{GWh} + (990 \text{ to } 1320)\ \text{GWh} \approx 998\text{–}1329\ \text{GWh/year}$$

Average Electrical Load: Assuming full-year operations (8760 hours), this corresponds to a continuous electrical base load of:

$$P = \frac{E_{\text{total}}}{8760\ \text{h}} \approx 114 \text{ to } 152\ MW$$

This represents a non-negligible share compared to the offshore energy export system capacity (e.g., 2100 MW for AC transmission). The steady electrical base load of the LNG terminal constitutes:

$$\frac{114 \text{ to } 152\ \text{MW}}{2100\ \text{MW}} \approx 5.4\% \text{ to } 7.2\%$$

Cable & Conversion Optimization: The steady, high base load of the LNG terminal offshore offers several potential synergies with the offshore transmission infrastructure:

- Cable sizing: With part of the generated electricity consumed offshore, the net export capacity required to shore is reduced. This may allow for downsizing AC cables or avoiding the need for additional transmission lines.
- AC Converter: Since the LNG system operates at a lower voltage, an additional AC converter with the same capacity as the LNG system is required. Although the HVAC conversion system capacity can be reduced, this does not lead to any financial benefits, as the added cost of the AC converter for the LNG operations offsets any savings (El Chahal, 2020).

The integration of an LNG terminal with a continuous electrical load offshore introduces an opportunity to slightly downsize the required AC export cable capacity. With a full-scale LNG terminal demanding an estimated steady electrical power supply of 114–152 MW, this energy is consumed offshore and does not need to be exported to shore. This reduces the net transmission requirement for offshore wind power.

G

Evaluation Of the Multifunctional Island

G.1. Overview of updated elements

Table G.1 outlines the updated supply chain elements of the energy system in the combined multi-functional case. Table G.2 outlines the updated supply chain elements of the port system in the combined multi-functional case.

G.2. Uncertainty & Sensitivity Analysis

To account for uncertainty in volatile energy markets, a copula-based simulation framework is applied to capture the dependency structure between historical gas and electricity prices. This enables realistic scenario generation that reflects market stress and demand shifts, supporting sensitivity analyses for both the LNG terminal and offshore wind energy system.

Objective: Model the joint distribution of gas and electricity prices to:

- Assess how gas price surges may coincide with electricity price volatility.
- Simulate joint price scenarios for use in revenue stress-testing of the offshore wind system and LNG terminal utilization.

Methodology Overview:

1. Data Collection: Obtain daily/monthly TTF gas prices and EPEX Spot Belgium electricity prices.
2. Marginal Distribution Fitting: Fit statistical distributions (e.g., lognormal) to each series.
3. Copula Selection: Fit a copula (e.g., t-copula or Clayton) to capture dependencies, especially in tails.
4. Scenario Generation: Use Monte Carlo simulation to generate realistic price scenarios.

The copula-based approach offers several advantages for modeling and analysis. It captures nonlinear dependencies between gas and electricity prices, particularly during periods of extreme market volatility, which are often the most critical for decision-making. By modeling the joint distribution of price variables, it enables correlated stress-testing of revenue streams across both the offshore wind and LNG regasification systems. This provides a more integrated and realistic assessment of financial risk. Furthermore, it supports probabilistic sensitivity analysis, allowing for a robust evaluation of uncertainties in market conditions and their impact on the economic feasibility of the island's multifunctional energy systems.

Application to Island Systems:

Electricity revenues for the offshore wind energy system are directly dependent on the market price of electricity (Beiter et al., 2020):

$$R_{\text{wind}} = P_{\text{elec}} \times E_{\text{produced}} \tag{G.1}$$

where P_{elec} is sampled from the copula-driven joint distribution of energy prices, and E_{produced} is the annual energy output from the offshore wind system.

Revenues from the LNG terminal are modeled as a function of the gas price

$$R_{\text{LNG}} = f(P_{\text{gas}}) \tag{G.2}$$

Here, f represents an increasing linear function.

To investigate the relationship between natural gas prices and LNG terminal revenues, an empirical analysis is carried out using historical data from the Fluxys LNG terminal. The aim is to establish a functional relationship that can be used to predict terminal revenues under varying gas price scenarios.

Table G.3 shows the yearly average gas prices and the corresponding revenues reported by the Fluxys LNG terminal for the years 2017–2023. Note that up until 2018, the terminal was largely underutilized, which likely weakens the price-revenue relationship in those years.

Table G.3: Fluxys LNG Revenue and Gas Prices (2017–2023) (CompanyWeb, 2025)

Year	Gas Price (EUR/kWh)	Revenue (EUR)
2017	19.96	97,200,000
2018	22.06	110,500,000
2019	14.35	145,000,000
2020	10.09	153,000,000
2021	46.16	169,000,000
2022	134.40	323,000,000
2023	40.17	220,000,000

A linear regression is applied to model the relationship between gas prices and terminal revenues. The resulting linear model is given by:

$$R = \beta_1 \cdot P_{\text{gas}} + \beta_0, \tag{G.3}$$

where R is the revenue, P_{gas} is the gas price, β_1 is the slope, and β_0 is the intercept. The estimated parameters are:

- Slope (β_1): 3 499 256 810.58
- Intercept (β_0): 60 579 516.15
- R^2: 0.9303
- p-value: 6.65×10^{-6}
- Standard error of slope: 338 721 752.15

Figure G.1 shows the relationship between the historical yearly average gas prices and the revenues generated by the Fluxys LNG terminal in Zeebrugge.

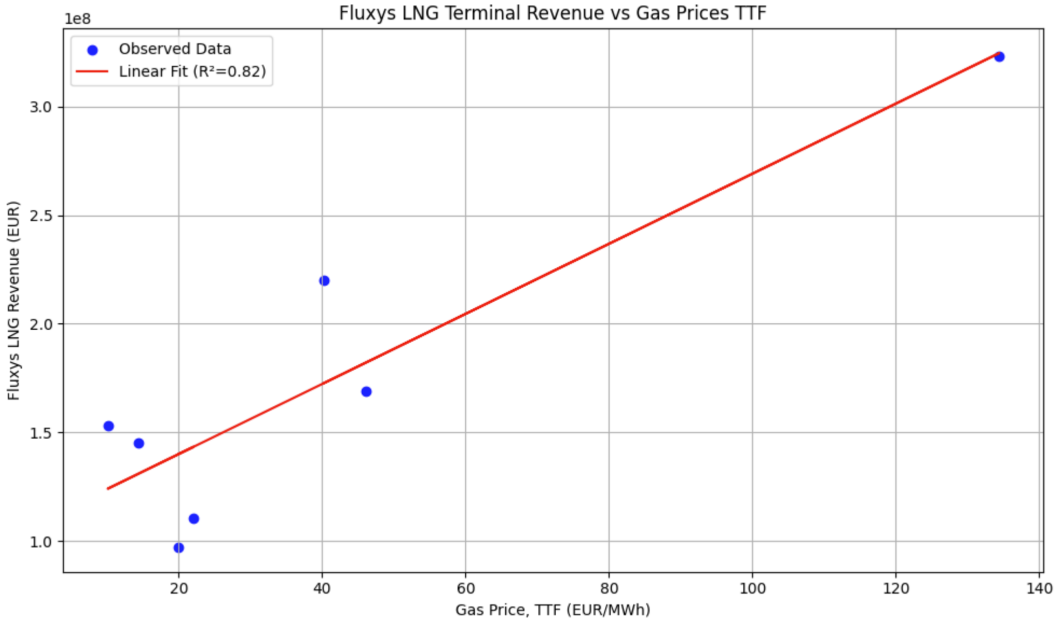


Figure G.1: Relation: Revenues LNG Terminal and Gas Prices (TTF, EUR/kWh)

These results suggest a strong and statistically significant positive relationship between gas prices and terminal revenues, particularly driven by the sharp increase observed in 2022. This is in line with the prior assumption that price spikes in the underlying commodity leads to increased terminal revenues, possibly due to increased trading activity, peak shaving demand, or favorable contract structures.

Copula-based dependence modelling between TTF Gas Prices and EPEX Spot prices

Following the modeling of the relationship between LNG terminal output and TTF gas prices, the next step involves capturing the dependence structure between TTF and EPEX electricity spot prices using copula functions. Copulas provide a flexible framework for describing the joint distribution of random variables independently of their marginal distributions, making them especially valuable when dealing with non-normal marginals or variables that exhibit tail dependence (Frikha and Lemaire, 2013, Patton, 2012).

Step 1: Transformation to uniform marginals

The first step involves transforming the marginal distributions of TTF and EPEX prices to the unit interval $[0, 1]$, as required by copula theory. This is achieved by applying the empirical cumulative distribution function (CDF) to each dataset:

$$u_{\text{TTF}} = F_{\text{empirical}}(X_{\text{TTF}}), \quad u_{\text{EPEX}} = F_{\text{empirical}}(X_{\text{EPEX}})$$

This produces two pseudo-observations (u, v) that are used to estimate the copula.

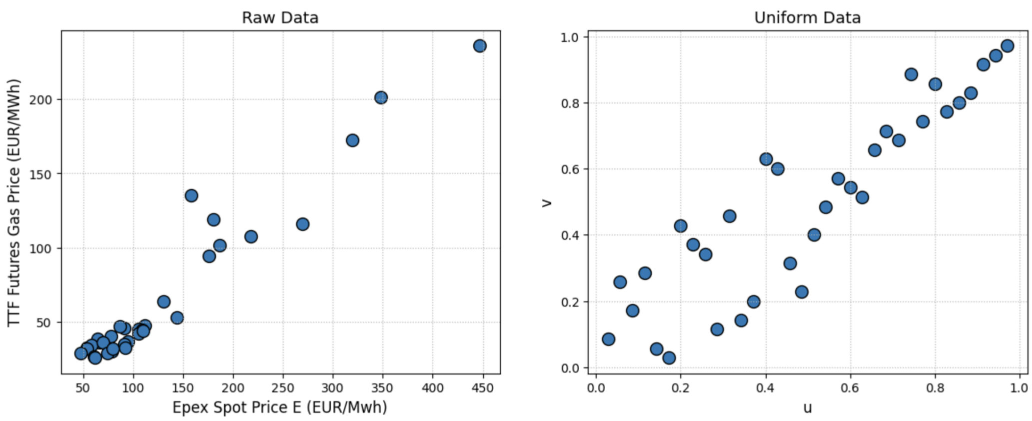


Figure G.2: Raw Data Transformation to Uniform Data

Step 2: Copula family selection and fitting

Several copula families are considered, including Clayton, Gumbel, Frank, and Joe, each of which captures different types of dependence structures (e.g., upper/lower tail dependence). For each copula family, the parameter is estimated using maximum likelihood estimation (MLE) based on the pseudo-observations.

The best-fitting copula is selected by comparing the log-likelihoods across copula families. The Joe copula is found to yield the highest log-likelihood, indicating the best fit for the observed joint behavior of TTF and EPEX prices. The fitted Joe copula parameter $\theta = 6.2$ is retained for further conditional analysis.

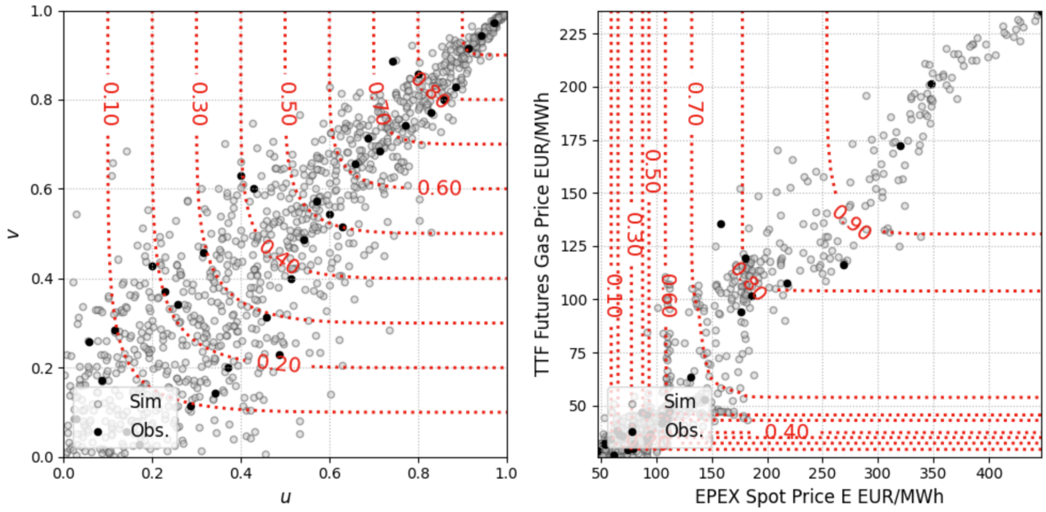


Figure G.3: Best Fitted Copula: Joe

Step 3: Conditional sampling via the h-function

To assess the conditional distribution of one variable given the other (e.g., TTF prices conditional on EPEX), the conditional distribution implied by the fitted Joe copula is utilized. The conditional copula, often referred to as the h-function, is defined for the Joe copula as:

$$C_{1|2}^{-1}(s_1 \mid u_2, \theta) = 1 - \left[1 - (1 - s_1)^{1/(\theta-1)} \cdot (1 - u_2)^{\theta}\right]^{1/\theta}$$

where s_1 is a uniform random sample representing the conditional probability, and u_2 is the copula-transformed value of the conditioning variable.

To generate conditional samples of TTF given a fixed EPEX price:

1. The fixed EPEX price is transformed into copula scale u_2 using the empirical CDF of the EPEX dataset.
2. A vector of uniform random values $s_1 \sim U(0, 1)$ is sampled.
3. The conditional copula inverse function is applied to obtain the conditional u_1 values.
4. Finally, these u_1 values are transformed back to real TTF prices using the empirical quantile function of the TTF dataset.

This method allows for generating realistic conditional samples from the joint distribution, useful for scenario analysis or stochastic simulations involving energy price dependencies.

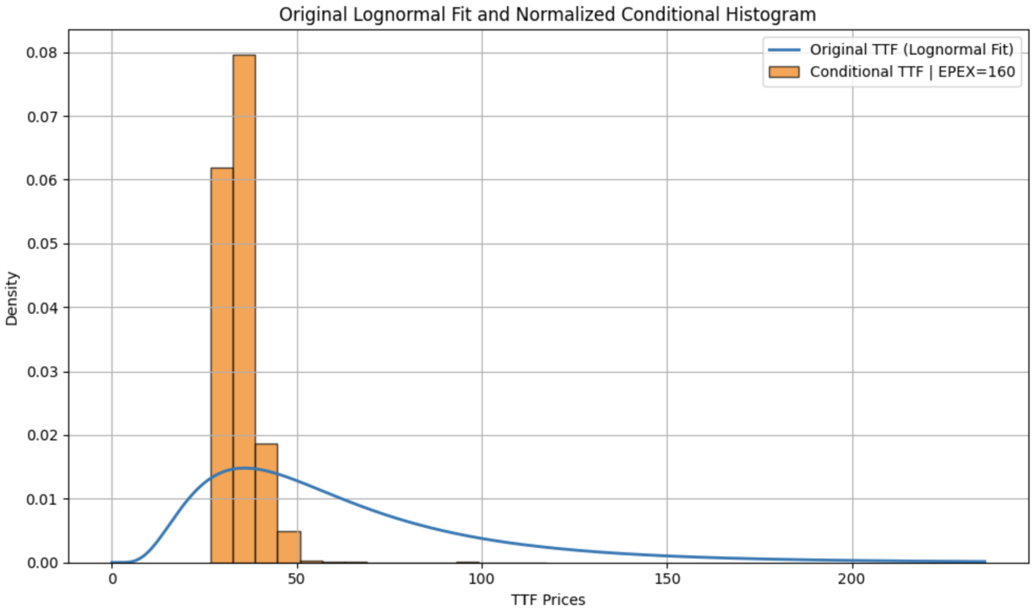


Figure G.4: Example: Conditional TTF Distribution for Fixed EPEX Spot Price of 160 EUR/MWh

Scenarios:
The values obtained from the copula correspond to monthly averages. For each year, we sample 12 values—one for each month—and average them. This process is repeated for every operational year of both systems (offshore wind energy system and LNG terminal), each having a 60-year lifetime. The revenue for each project is calculated by adding the sampled values to the respective systems' cash flows, and the final Net Present Value (NPV) for each project is determined in the last year of operation. This process is repeated for 1,000 simulations, allowing us to generate distributions of the final NPV values for both projects.

The following three scenarios are considered for the copula sampling:

1. Just Copula Sampling: This scenario employs a Joe copula with a parameter $\theta = 6.2$, fitted from historical data, to generate the dependencies between the energy prices (EPEX and TTF). The copula is sampled directly without conditioning on any other prices.
2. Conditional Copula (EPEX Conditionalized over TTF): A deterministic forecast of the TTF price is defined for each year over the 60-year period. Based on this forecast, the EPEX price is sampled conditionally over the TTF using the copula, allowing the dependency between these two price dynamics to be reflected.
3. Conditional Copula (TTF Conditionalized over EPEX): A deterministic forecast of the EPEX price is defined for each year over the 60-year period. Subsequently, the TTF price is sampled conditionally over the EPEX price using the copula, capturing the relationship in the reverse direction.

Figure G.5 illustrates the price scenarios for both TTF and EPEX over the next 60 years.

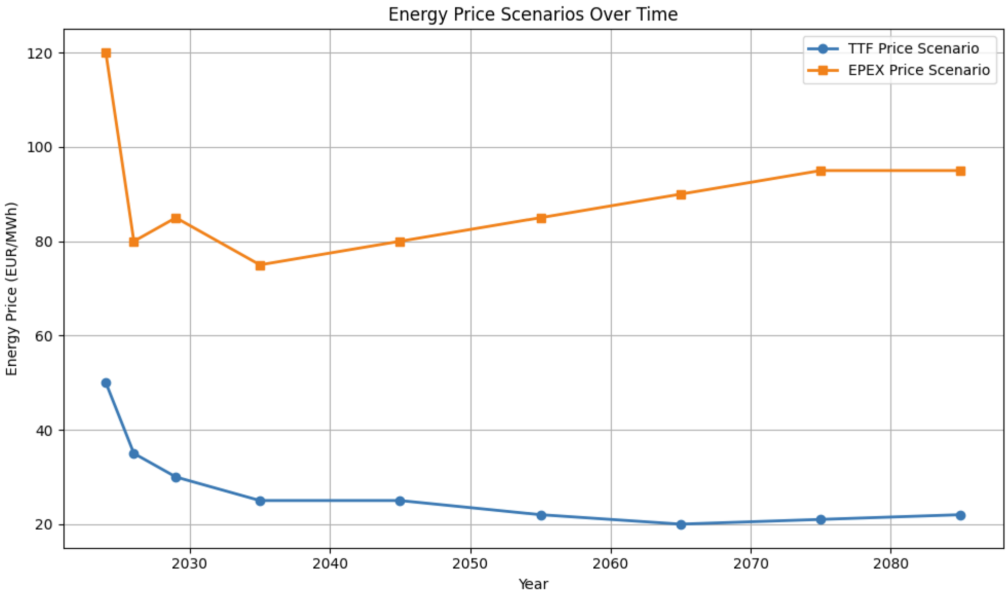


Figure G.5: Energy Price Scenarios by Montel (EnergyBrainpool, 2025)

Component	Element Name	Capacity/Dimension	Unit Cost []	CAPEX [EUR m]	OPEX [%]	Insurance rate [%]	Lifetime [years]	Decom. rate [%]]
AC Equipment		**2.1 GW**		**2750**				
	Offshore AC Substation Phase 1	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 1 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	Offshore AC Substation 2 Phase 3	700 MW	208 [EUR m/asset]	208	2	0.5	30	2
	AC Export Cables	310 km	4.05 [EUR m/km]	1250	2	0.5	25	2
	Onshore AC Cables	40 km	4.05 [EUR m/km]	162	2	0.5	25	2
	Onshore AC Substation (X3)	2.1 GW	208 [EUR m/asset]	624	2	0.5	30	2
HVDC Equipment		**1.4 GW**		**4160**				
	HVDC Converter Station	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
	HVDC Export Cables	55 km	4.05 [EUR m/km]	223	2	0.5	25	2
	Onshore HVDC Cables	10 km	4.05 [EUR m/km]	40.5	2	0.5	25	2
	Onshore HVDC Converter	1.4 GW	1.4 [EUR m/MW]	1950	2	0.5	30	2
Offshore Wind Farms		**3.5 GW**		**5864**				
	Windturbines Phase 1	700 MW	1.5 [EUR m/MW]	1050	2	0.5	20	2
	Windturbines Phase 2	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Windturbines Phase 3	1400 MW	1.5 [EUR m/MW]	2100	2	0.5	20	2
	Array Cables Phase 1	130 km	1.2 [EUR m/km]	156	2	0.5	25	2
	Array Cables Phase 2	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
	Array Cables Phase 3	260 km	1.2 [EUR m/km]	312	2	0.5	25	2
Artificial Island		**25 ha**		**920.5**				
	Island Caissons	23	16.5 [EUR m/unit]	380	1	0.5	80	1
	Island Sand Core	510x510x30m^3(30%)	8.3 [EUR/m^3]	20.5	1	0.5	80	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400	1	0.5	80	1
	Quaywall	300m	0.125 [EUR m/m]	38	1	0.5	50	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23	2.5	0.5	25	1
	Cable Landing Facilities	1	20 [EUR m/unit]	20	2	0.5	30	2

Table G.1: Multifunctional Island Updated Energy System Elements and Associated Costs

Table G.2: Cost Breakdown and Technical Parameters of offshore LNG Terminal System in combined case (Sooby, 2020, Özelkan et al., 2008)

Component	**Element Name**	**Capacity/Dimension**	**Unit Cost []**	**CAPEX [EUR]**	**Lifetime [years]**	**OPEX [%]**	**Insurance rate [%]**	**Decom. rate [%]]**
Artificial Island								
	Island Caissons	23	16.5 [EUR m/unit]	380,000,000	80	1	0.5	1
	Island Sand Core	510x510x30m^3 (70%)	8.3 [EUR/m^3]	38,300,000	80	1	0.5	1
	Bed Protection/Rockberm	1000m	400 [EUR k/m]	400,000,000	80	1	0.5	1
	Sand Reclamation	2.8 million m^3	8.3 [EUR/m^3]	23,000,000	25	2.5	0.5	1
Marine Works								
	Breakwater	1.5 km in 15m depth	54,000 EUR/m	83,000,000	40	0.03	0.005	0.02
	Jetty and Berths	2 units	35,000,000 EUR/asset	70,000,000	25	0.04	0.005	0.02
	Navigation Aids	-	3,000,000 EUR/asset	3,000,000	25	0.02	0.005	0.02
Cryogenic Transfer								
	Unloading Arms	4 units	3,000,000 EUR/asset	12,000,000	25	0.06	0.005	0.02
	LNG Pipeline	2 km	5,000 EUR/m	10,000,000	25	0.06	0.005	0.02
Storage								
	LNG Tanks	900,000 m^3	450 EUR/m^3	400,000,000	30	0.07	0.005	0.02
Regasification								
	Vaporizers	6.6 mtpa	17,000,000 EUR/mtpa	110,000,000	25	0.04	0.005	0.02
	BOG System	1% boil-off	15,000,000 EUR/asset	15,000,000	25	0.04	0.005	0.02
Miscellaneous								
	Utilities	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Control and Safety	-	10,000,000 EUR/asset	10,000,000	30	0.02	0.005	0.02
	Land and Permitting	-	20,000,000 EUR/asset	20,000,000	40	0.02	0.005	0.02
Gas Export								
	Pipeline & Compressor	40 km	3,300 EUR/m	200,000,000	30	0.02	0.005	0.02

H

LNG Regasification & Transshipment at the Port of Bruges

H.1. Current Numbers

The Zeebrugge LNG Terminal is a cornerstone of Europe's LNG logistics, with a transshipment capacity of 8 million tonnes per annum (mtpa), supported by a dedicated storage tank of 180,000 cubic meters. As of 2024, the facility has reached full booking capacity for its transshipment berthing rights and storage until 2039, driven by long-term agreements such as the Yamal LNG contract.

Table H.1: LNG Throughput at Zeebrugge Terminal (2010–2021) (CompanyWeb, 2025).

Year	Discharged (tons)	Loaded (tons)	Total (tons)
2021	6,070,093	3,041,060	9,111,153
2020	7,313,761	3,776,551	11,090,312
2019	6,184,619	1,373,785	7,558,404
2018	2,746,945	930,121	3,677,066
2017	935,398	92,600	1,027,998

In addition to its transshipment capabilities, the terminal's rapid loading rates exceed **12,500 cubic meters per hour**, ensuring operational efficiency for the growing LNG trade. Figure H.1a shows the trend of LNG throughput from 2010 up until 2022 (Zeebrugge, 2021).

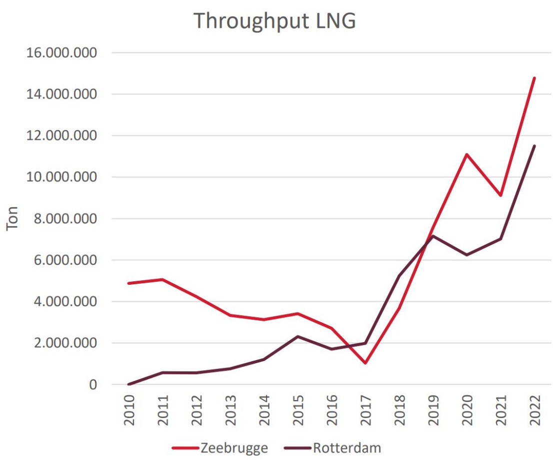
H.2. Current Revenue

Revenue at Zeebrugge's LNG terminal stems primarily from berthing rights and storage fees. Due to high demand, the facility's transshipment services are fully booked until **2039**. The key revenue components include (Fluxys, 2024a):

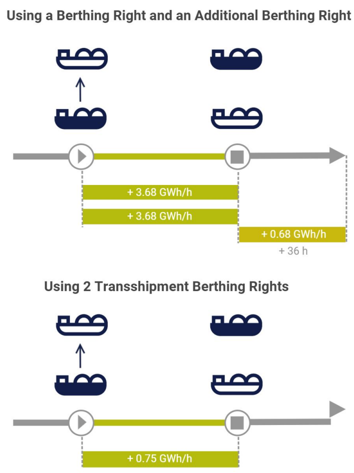
Table H.2: Revenue Streams from Transshipment Operations.

Revenue Stream	Tariff/Volume
Transshipment Berthing Right	€147,549.07 per ship
Additional Berthing Right	€87,509.43 per ship
Storage Cost	€0.058 per MWh/day

The long-term contracts, particularly with Yamal LNG and Qatar Petroleum, ensure consistent revenue generation through 2044. Auxiliary services like truck loading, vessel bunkering, and small-scale LNG operations further bolster income.



(a) Throughput of LNG in Bruges and Rotterdam (Zeebrugge, 2021).



(b) Transhipment costs at port of Bruges (Fluxys, 2024a).

Figure H.1: LNG Throughput and Transhipment Costs at Port of Bruges .

H.3. Market Outlook

The demand for LNG transshipment at Zeebrugge is driven by its strategic location and operational efficiency. With the recent capacity expansion in 2024 adding 4.7 mtpa and bringing total capacity to 11.3 mtpa, the terminal is well-positioned to meet current demand.

Key factors contributing to market growth include (Arnouts, 2023):

- Global LNG Demand: Rising LNG consumption in Asia-Pacific and Europe.
- Expanded Capabilities: Infrastructure like the Dunkirk-Zeebrugge Pipeline (8 bcm/y) supports intermodal LNG flows across Europe.
- Strategic Booking: Full booking of transshipment rights through 2039 highlights the terminal's critical role in global LNG supply chains.
- Supply gap: An increase in the supply gap, caused by the diminishing share of Russian gas imported by pipeline, will result in more LNG being shipped by vessels. figure H.2 shows this evolution of the european market

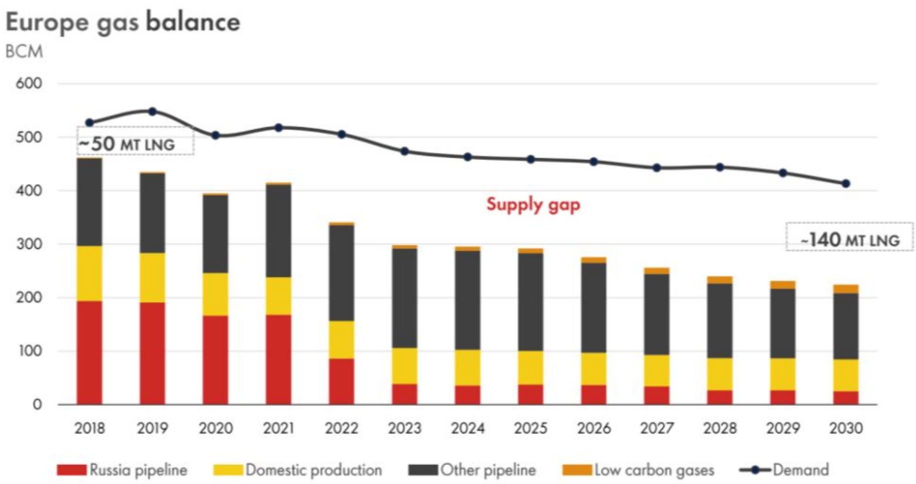


Figure H.2: LNG market projection Europe (Arnouts, 2023).

H.4. Geopolitics: The Effect of the Russian-Ukrainian Conflict

The ongoing Russian-Ukrainian conflict has further emphasized the importance of LNG in Europe's energy strategy. The Zeebrugge terminal, already integral to LNG logistics, has seen increased reliance as Europe pivots away from Russian pipeline gas (Arnouts, 2023).

Between 2021 and 2023, 90% of Yamal LNG exports transshipped through Zeebrugge were destined for non-European markets, such as Asia and South America. This reliance on Russian LNG for international markets has drawn scrutiny, with reports estimating that Zeebrugge facilitated €717 million in Russian LNG shipments in the months following the conflict's escalation.

Table H.3: LNG Imports at Zeebrugge by Source (Arnouts, 2023).

Source	Volume (tons)
Russia	4,000,000
Qatar	3,500,000
USA	2,800,000
Others	1,200,000

Despite these challenges, the terminal's advanced infrastructure and long-term contracts underscore its resilience in a volatile geopolitical environment.

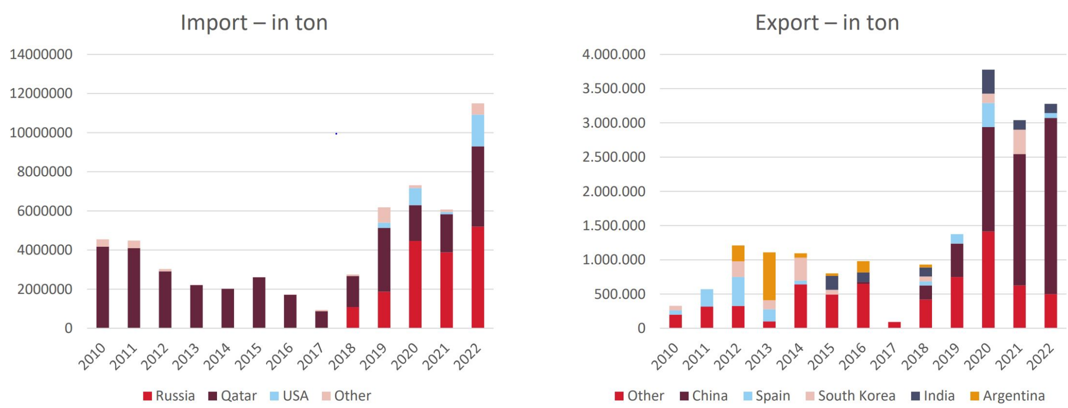


Figure H.3: Origin and destination of LNG carriers in port of Bruges (Arnouts, 2023).

I

OpenTESim

The software related to both the framework and case, presented in this thesis can be accessed using the QR code below or the following URL: https://github.com/TUDelft-CITG/OpenTESim/tree/MasterThesisSamuel/case

Figure I.1: QR Code OpenTESim

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