# Unlocking the North Sea

## Cross-border collaboration mechanism for effective sharing of costs, benefits, and risks of North Sea electricity infrastructure

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TU Delft

Ministerie van Klimaat en Groene Groei

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## Cross-border collaboration mechanism for effective sharing of costs, benefits, and risks of North Sea electricity infrastructure

by


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TU Delft

# Preface

It is with great excitement and relief that I approach the end of my student life as I write this preface, though also with some sorrow, as the wonderful time I had at the Ministry is coming to an end. The process of writing this master's thesis was challenging at times. At first, I had little knowledge of the cost-sharing domain and felt as though I was stepping into something much bigger than myself; then, as my understanding grew, it seemed there was always another layer to this problem that I could not fully capture. In the end, with guidance from the very smart people at the Ministry, I was able to capture enough depth to convey the right message. Without the opportunity provided by the Ministry of Climate Policy and Green Growth, I would not have been able to achieve this quality of work or specialize in this topic to the degree that I have.

First and foremost, I would like to thank Ellinore, my supervisor at the Ministry, for making me feel so welcome and making everything so much easier. I am equally grateful to Kim, my manager, for the trust you placed in my abilities from the very first day. A heartfelt thank you also goes to Alice, Amra, and Bente from the cost-sharing team, to Jeroen for including me in internal discussions and providing valuable input, and to all my colleagues from the FEA, for their support throughout. At TU Delft, Laurens, Kenneth, and Anas played a huge role in helping me develop the analytical framework upon which this research is based, and I am very grateful for their guidance. Both at the Ministry and at TU Delft, I was given a great deal of freedom to explore the field, choose my own focus, and define my own boundaries in how I approached the problem. Thanks to your trust and encouragement, I was able to undertake this task.

I would also like to thank my parents, Asım and Burcu, without whom my education would not have been possible in the first place. I am grateful for everything they have done for me. My friends from Istanbul and the Netherlands also deserve recognition for the supportive role they played in my well-being throughout my time as a student; we have shared some great moments, and I hope many more will follow. As I look forward to what my future as a specialist in the field of energy holds, I hope you enjoy reading this thesis as much as I enjoyed writing it.

*Kerem Gün*
*Delft, May 2026*

# Abstract

Expanding offshore wind in the North Sea is central to Europe's ambition to deliver affordable, clean, and secure energy. However, the benefits of offshore wind and interconnector investments are distributed cross-border through market coupling, while the associated costs remain largely national, borne by consumers through grid tariffs and by government budgets. This fundamental mismatch between where benefits accrue and where costs fall has proven politically difficult: existing cross-border cost allocation frameworks have defaulted to the territorial principle in over 70% of decisions, meaning each country simply pays for infrastructure within its own borders, producing little to no cross-border redistribution in practice. This thesis investigates what cross-border collaboration model would enable the effective development of a large-scale offshore electricity system in the North Sea, while reflecting participating countries' differing costs, benefits, and risks.

To address this, a two-country partial-equilibrium model of coupled electricity markets is developed, in which investment decisions are modelled as a non-cooperative Nash game across eight probabilistically weighted operating regimes. A set of cost-sharing mechanisms is systematically evaluated on how well they achieve collectively optimal outcomes, distribute costs fairly, and create room for countries to reach agreement. These include the equal-split and benefit-proportional ex-ante allocation rules; a cross-border Contract for Difference for transmission, a financial instrument that redistributes costs between countries after the fact based on realized benefits; and a cross-border generation Contract for Difference, the standard government support scheme used across Europe to guarantee offshore wind developers a fixed revenue, here extended so that two national governments jointly act as counterparty rather than one.

The results consistently show that countries underinvest relative to what would be optimal for the collective system as a whole under all mechanisms. Benefit-proportional allocation outperforms the equal split by better reflecting realized benefits, bringing agreed expansion closer to the system optimum. The transmission CfD yields the largest improvement in investment efficiency but is highly sensitive to strike price calibration and exposes the non-host country to obligations that may be unknown and politically difficult prior to project realization. The generation CfD expands the feasible negotiation space, and combining instruments does not monotonically improve outcomes. Crucially, no mechanism produces mutually agreeable investment outcomes that are not sensitive to divergent expectations about future market conditions, revealing that institutional alignment on shared forecasting frameworks is a necessary complement to any financial instrument.

The proposed collaboration model uses benefit-proportional allocation ex-ante, applied to as broad a cost scope as possible, complemented by a cyclically calibrated transmission CfD with an ex-ante defined divergence threshold and correction cap. These building blocks should be embedded earlier in the planning process as a structuring constraint rather than a final redistributive step, and should be pursued first on the basis of established bilateral trust before scaling to the broader North Sea.

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# Nomenclature

## Abbreviations

| Abbreviation | Definition |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| ACM | Authority for Consumers and Markets |
| BP | Benefit-Proportional |
| CACM | Capacity Allocation and Congestion Management |
| CAPEX | Capital Expenditures |
| CBA | Cost-Benefit Analysis |
| CBCA | Cross-Border Cost Allocation |
| CB RES | CEF Cross-Border Renewable Energy |
| CEF | Connecting Europe Facility |
| CEF-E | CEF Energy |
| CEER | Council of European Energy Regulators |
| CfD | Contract for Difference |
| CID | Congestion Income Distribution |
| CINEA | European Climate, Infrastructure and Environment Executive Agency |
| DEVEX | Development Expenditures |
| EEZ | Exclusive Economic Zone |
| EIB | European Investment Bank |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ENTSO-G | European Network of Transmission System Operators for Gas |
| ESP | Equal Share Principle |
| EU | European Union |
| EUPHEMIA | Pan-European Hybrid Electricity Market Integration Algorithm |
| EVC | Economic Viability Check |
| EZK | Ministry of Economic Affairs and Climate Policy (Netherlands) |
| FID | Final Investment Decision |
| FTR | Financial Transmission Right |
| GW | Gigawatt |
| HVDC | High-Voltage Direct Current |
| IC | Interconnector |
| ITC | Inter-TSO Compensation |
| KKT | Karush-Kuhn-Tucker |
| MC | Marginal Cost |
| MinKGG | Ministry of Climate Policy and Green Growth (Netherlands) |
| MoU | Memorandum of Understanding |
| MRQ | Main Research Question |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NBNL | Netbeheer Nederland |
| NPE | National Energy System Plan |
| NRA | National Regulatory Authority |
| NSEC | North Sea Energy Cooperation |
| OBZ | Offshore Bidding Zone |
| OPEX | Operational Expenditures |
| OTC | Offshore TSO Collaboration |
| OWF | Offshore Wind Farm |

| Abbreviation | Definition |
|---|---|
| PCI | Project of Common Interest |
| PINT | Put-In-One-at-a-Time |
| PMI | Project of Mutual Interest |
| PNBD | Positive Net Benefit Differential |
| PROMOTioN | Progress on Meshed HVDC Offshore Transmission Networks |
| RAB | Regulatory Asset Base |
| RED II | Renewable Energy Directive II |
| RENEWFM | Renewable Energy Financing Mechanism |
| RES | Renewable Energy Sources |
| RQ | Research Question |
| SB-CBS | Sea-Basin Cross-Border Cost-Sharing |
| SDE++ | Stimulering Duurzame Energieproductie en Klimaattransitie |
| SEW | Socio-Economic Welfare |
| SV | Shapley Value |
| TEN-E | Trans-European Networks for Energy |
| TOOT | Take-Out-One-at-a-Time |
| TOTEX | Total Expenditure |
| TSO | Transmission System Operator |
| TYNDP | Ten-Year Network Development Plan |

# Symbols

Subscript $n \in \{x, y\}$ denotes the country; subscript $r \in \{1, \ldots, 8\}$ the operating regime. Country $x$ is the renewable-rich host and country $y$ the supply-constrained importer. The model operates under a single-period convention in which one period corresponds to one hour; quantity variables (flows, generation, consumption) are therefore expressed in [MWh] and capacity variables in [MW], with the two units numerically equivalent throughout.

| Symbol | Definition | Unit |
|---|---|---|
| **Demand parameters** | | |
| $\bar{\lambda}_n$ | Choke price (maximum willingness to pay) of country $n$ | [€/MWh] |
| $a_n^D$ | Inverse demand slope of country $n$ | [€/MWh$^2$] |
| $\lambda_n(q_n)$ | Inverse demand function (nodal price) of country $n$ | [€/MWh] |
| **Supply parameters** | | |
| $a_n^S$ | Marginal cost slope of dispatchable generation in country $n$ | [€/MWh$^2$] |
| $q_{n,RES}$ | Baseline exogenous RES injection at node $n$ | [MWh] |
| **Market-clearing variables** | | |
| $q_n$ | Cleared consumption at node $n$ | [MWh] |
| $g_n$ | Dispatchable generation at node $n$ | [MWh] |
| $f$ | Interconnector flow (positive: $x \to y$) | [MWh] |
| **Capacity and expansion** | | |
| $K$ | Existing interconnector capacity | [MW] |
| $\Delta K$ | Expansion in interconnector capacity | [MW] |
| $\Delta q_{x,RES}$ | Expansion in offshore wind injection at country $x$ | [MWh] |
| **Costs** | | |
| $c_{trans}$ | Unit investment cost of interconnector expansion | [€/MW] |
| $c_{radial}$ | Unit investment cost of radial offshore connection | [€/MW] |
| $C_{trans}$ | Total interconnector investment cost | [€] |
| $C_{radial}$ | Total radial connection investment cost | [€] |

| Symbol | Definition | Unit |
|---|---|---|
| $C_n$ | Investment cost allocated to country $n$ | [€] |
| $C^{tot}$ | Total system investment cost | [€] |
| **Welfare components** | | |
| $CS_n^r$ | Consumer surplus of country $n$ in regime $r$ | [€] |
| $PS_n^r$ | Producer surplus of country $n$ in regime $r$ | [€] |
| $CR^r$ | Total congestion rent in regime $r$ | [€] |
| $CR_n^r$ | Congestion rent allocated to country $n$ in regime $r$ | [€] |
| $\mathit{NetSEW}^r$ | Net socio-economic welfare in regime $r$ | [€] |
| $\mathit{NetSEW}_n^r$ | Country-level net SEW of country $n$ in regime $r$ | [€] |
| $E[\mathit{NetSEW}]$ | Expected net SEW (aggregated across regimes) | [€] |
| $B_n$ | Realized economic benefit of country $n$ | [€] |
| $B^{tot}$ | Total realized system benefit | [€] |
| $U_n$ | Expected net welfare of country $n$ in the strategic game | [€] |
| **Cost-sharing** | | |
| $\alpha_n$ | Cost-sharing key (fraction of costs) allocated to country $n$ | [–] |
| **Contract for Difference instruments** | | |
| $\lambda_{CfD}^{trans}$ | Strike price of the transmission CfD | [€/MWh] |
| $\lambda_{CfD}^{gen}$ | Strike price of the generation CfD | [€/MWh] |
| $CfD_n^{trans}$ | Transmission CfD transfer received by country $n$ | [€] |
| $CfD_n^{gen}$ | Generation CfD payment made by country $n$ to the OWF | [€] |
| **Regime weights** | | |
| $\omega_r$ | Probability weight of operating regime $r$ | [–] |
| $\tilde{\omega}_r$ | Normalized weight of regime $r$ over feasible regimes | [–] |
| **KKT dual variables** | | |
| $\mu^+$ | Dual variable for upper interconnector flow limit ($f \leq K$) | [–] |
| $\mu^-$ | Dual variable for lower interconnector flow limit ($f \geq -K$) | [–] |
| $\nu_x$ | Dual variable for non-negative dispatchable generation at $x$ | [–] |
| $\nu_y$ | Dual variable for non-negative dispatchable generation at $y$ | [–] |
| **Strategic game and performance metrics** | | |
| $i, j$ | Grid indices for interconnector and wind expansion | [–] |
| $(i^{SO}, j^{SO})$ | System-optimal expansion point (global SEW maximum) | [–] |
| $(i^*, j^*)$ | Nash equilibrium expansion point | [–] |
| $(i^\dagger, j^\dagger)$ | Welfare-maximizing Nash equilibrium among agreed outcomes | [–] |

# 1
# Introduction

## 1.1. The potential of the North Sea electricity system

The move towards a more sustainable energy system in the EU, defined by a steadily diminishing share of fossil fuels, is an inevitable trajectory if the 2030 and 2040 emission reduction goals and full carbon-neutrality by 2050 are to be achieved. However, the current capacity of the European grid is inadequate to pave the path to reach these goals. Crises in the recent past have been a reminder of the need to ramp up domestic sustainable energy production and strengthen the electrical grid. Following the difficulties and global energy market disruption after Russia's invasion of Ukraine, the European Commission has implemented the REPowerEU Plan to phase Russian fossil fuel imports. According to European Commission (2024), infrastructure improvements, in terms of generation and transmission capacity, in the North Sea will be key to provide affordable clean energy to all of Europe while reducing dependence on Russia as an energy supplier. To enable this progress, significant expansion of the electricity grid must be undertaken in order to prevent a major economic and societal bottleneck (MinKGG, 2025).

Offshore wind energy in the North Sea has the potential to increase domestic European energy generation drastically and reduce dependency on fossil fuels and unreliable providers. This will deliver competitive electricity prices, thus support industrial competitiveness and provide affordable prices to consumers (European Commission, 2024). On this point, Member States of the European Union have agreed on ambitious regional offshore wind energy goals- 120 GW by 2030 and 300 GW by 2050 (European Commission, 2026). Of the Member States, nine have expressed a "shared" ambition to increase offshore wind energy capacity in the North Sea: Belgium, Denmark, France, Germany, Ireland, Luxembourg, The Netherlands, Norway, and the United Kingdom (Meeus, 2025). This shared ambition is solidified via the Ostend Declaration, signed by the nine Member States (Gephart, 2025).

## 1.2. Costs and benefits of interconnectors and offshore wind energy in the North Sea

For the wind energy to be evacuated to shore- where the load is, high-capacity high-voltage direct current (HVDC) transmission lines are required. The future ideal North Sea electricity system is a meshed grid of many high-capacity transmission lines as outlined by PROMOTioN Consortium (2020), which is an overarching definition that surpasses any one country's national vision. It will contain radial unilateral (for evacuating offshore wind to shore), and point-to-point bilateral as well as hybrid transmission assets. Connecting bidding zones via these structures serve to arbitrate prices across borders, optimizing the overall energy system. Whereas hybrids can potentially integrate offshore wind energy capacities and fundamentally change the energy mixes of the region and help achieve decarbonization (European Commission, 2024).

There are many benefits associated with a fully realized electrical system in the North Sea, consisting of interconnected markets and expanded offshore wind. European Commission (2025a) identifies energy security and economic/industrial competitiveness as central political objectives, referencing the Draghi report[1] as a key foundation. These priorities form the underlying rationale for elevating the strategic importance of electricity grids within the European policy agenda. Upon the benefits reaped by the integration of decentralized European electricity markets, lowering energy prices and providing affordable living conditions for all Europeans, provision of secure and reliable energy supply, allowing Member States to support one another during times of need, and the phasing out of Russian energy imports as part of the RePowerEU[2] are identified as critical. Willems, Brandstätt, Nieuwenhout, Le Coq, and Serrien (2025) identifies the monetizable and non-monetizable benefits for increased transmission capacity across borders presented in Table 1.1.

**Table 1.1:** Key Benefit Indicators for CBA (ENTSO-E) in line with TEN-E Regulation (Willems, Brandstätt, Nieuwenhout, Le Coq, and Serrien, 2025)

| Indicator | Unit | Approach | TEN-E Criteria |
|---|---|---|---|
| Socio-economic Welfare | /yr | Short-run economic rents: consumer, producer and congestion, cross-sectoral and storage. Calculated through an interlinked hydrogen and electricity market model. | Market integration, Sustainability |
| $CO_2$ emissions | Tons/yr<br>/yr | Emission reduction is first expressed in tons to align with political targets. Emission trading is already incorporated into SEW benefits. To avoid double-counting, the difference between the social cost of carbon and the ETS price is considered as an additional monetary benefit.[5] | Sustainability |
| Renewables integration | MW<br>MWh/yr | The reduction of renewable curtailment and/or the amount of renewable capacity directly connected by the project, calculated through market and redispatch simulations.[5] | Sustainability |
| Non-$CO_2$ emissions | Tons/yr | Calculated based on yearly power plant generation patterns [MWh] and emission factors [t/MWh] through market and redispatch simulations. Possible emissions include NO, CO, $SO_2$, and particulates. | Sustainability |
| Grid losses | MWh/yr | Losses are calculated through power flow simulations. Demand curves already include grid losses as they are based on historical time series. Compensation is therefore necessary to avoid double-counting with SEW. | Energy efficiency |
| Adequacy | MWh/yr | Expected energy not served is calculated using Monte Carlo-based market simulations. Note that the adequacy assessments are calculated assuming fixed generation capacities. | Security of Supply |
| Flexibility | Ordinal | Methodology is under development. | Security of Supply |
| Stability | Ordinal | Methodology is under development. | Security of Supply |
| Reduction of necessary reserve for redispatch power plants | MWh/yr | The maximum redispatch power is calculated through redispatch simulations. It serves as a proxy for the required redispatch capacity. Some countries have specific mechanisms for contracting redispatch reserve power plants. | Security of Supply |

Although the benefits of expansion in European energy infrastructure capacity are acknowledged by the Union, they also acknowledge the insufficiency of the current pace of developments. According to European Commission (2025a), the Member States are not on track to meet the 15% interconnection target by 2030 due to underinvestment and insufficient integration, with impending direct impact on energy bills. Materializing these

[1] https://commission.europa.eu/topics/competitiveness/draghi-report_en
[2] https://commission.europa.eu/topics/energy/repowereu_en

benefits through cross-border electricity imports in the North Sea therefore requires expanding both interconnection capacity that carry the flows and generation capacity in neighboring countries to supply them (ACER-CEER, 2024).

Estimates for the required investment amount for the offshore grid in the North Sea varies by source. Gephart (2025) presents a figure of € 260 billion internationally, while Interdepartementaal Beleidsonderzoek Elektriciteitsinfrastructuur (2024) indicates that € 88 billion of investment (from a total of € 195 billion within the greater Netherlands) in relevant offshore infrastructure will be required within the Dutch EEZ. A large volume of affordable capital is required to enable financing of the offshore electricity system, but the public finances are increasingly strained, and deploying capital at the required scale is increasingly challenging. The expected costs are too high for a unilateral approach to financing them.

ENTSO-E (2025) emphasizes the requirement for achieving the ambitious renewable energy targets- coordinated investment in offshore infrastructure, adding that political and strategical consensus among European countries are critical enablers of progress. Currently almost all countries of the North Sea have mutual Memorandum of Understanding (MoUs) while there is little to no certainty that these MoUs will give rise to a successful portfolio of transmission asset projects. Structural and financial obstacles prevent the timely deployment of affordable public and private capital into offshore wind and transmission infrastructure, which altogether strengthen the notion that European countries must strengthen cross-border cooperation to boost investment in shared energy infrastructure (Gephart, 2025).

A key economic challenge is that the full range of costs and benefits of any offshore wind or interconnector expansion do not all accrue to the same country. When one country expands generation or grid capacity, the resulting electricity flows affects wholesale prices in all surrounding markets — raising prices in the exporting region and suppressing them in the importing one — such that a portion of the investing country's welfare gains leak across the border, while its partner captures benefits without contributing to costs (Willems et al., 2025). This distorts national investment incentives away from the socially optimal level, and quantitative analysis of integrated North Sea configurations confirms that these cross-border price effects can be substantial, with net benefits distributed highly asymmetrically between countries (Konstantelos et al., 2017).

## 1.3. Problem statement and research objective

The North Sea offshore electricity system cannot be realized through unilateral national action: the investment required to meet the Ostend Declaration's offshore wind targets far exceeds what any single country can reasonably finance alone. The frameworks tasked with bridging this gap have not only failed to produce cross-border redistribution in practice, but have left the fundamental question of how costs should be shared methodologically unanswered. No agreed-upon operational framework exists. The recently published EU Grids Package signals awareness of the problem but stops short of resolving it. More fundamentally, even the frameworks that do exist are oriented almost exclusively toward hybrid interconnector configurations, leaving domestically sited offshore wind investments, whose benefits spill across borders just as surely, entirely outside the scope of any cost-sharing governance. In the academic literature, existing work is either tied to specific project configurations or lacks a consistent analytical basis for isolating how individual mechanism design choices shape investment incentives and the scope for bilateral agreement.

This thesis contributes to the academic literature by consolidating the surrounding policy and regulatory context, identifying the structural sources of the cost-sharing problem, and examining how specific mechanism design choices influence investment incentives, welfare distribution, and the scope for bilateral agreement. Rather than proposing a ready-to-deploy solution, the analysis isolates the individual and combined effects of existing and proposed cost-sharing components, with the aim of informing future mechanism design and providing the Ministerie van Klimaat en Groene Groei with a structured analytical basis for their ongoing work within the cost-sharing context.

## 1.4. Research questions

This section provides the research questions and how they will be addressed, and the scope of the study. The thesis research will be seeking answers to the questions provided.

**Main Research Question (MRQ) - What cross-border collaboration model would enable the effective development of a large-scale offshore electricity system in the North Sea while reflecting participating countries' differing costs, benefits, and risks?**

Description - This is the overarching question addressed through the individual RQs. It captures the broad scope and shared ambition underlying cross-border collaboration for offshore infrastructure investments. It captures the primary objective of the research within the context of the internship- providing the Ministry of Climate Policy and Green Growth with a full picture of the problem of cost-sharing, and an overview of the existing economic toolset to alleviate some of its burdens.

Scope - Although the research question addresses which mechanism or financial tool could create the right incentives for voluntary contributions at a system-wide level across the greater North Sea, the methodological approach of this study focuses on a much smaller scale—specifically, on interactions between only two countries (bilateral case). This simplification allows for a clearer assessment of the cost sharing tools. The process, can in theory, be scaled up and applied to a broader range of projects and involve more than two participating nations.

The subsequent RQs form a step-by-step process for understanding the problem, comparing known cost-sharing methods, and proposing an alternative to the status-quo:

**RQ 1: How does the cross-border nature of offshore electricity infrastructure create distributional challenges that existing regulatory and policy arrangements struggle to overcome?**

This question examines how market coupling causes the costs and benefits of offshore wind and interconnector investments to be distributed asymmetrically across countries, and assesses the extent to which the existing cost-sharing and surrounding framework, which includes the CBCA and the EU Grids Package, are equipped to address these asymmetries.

**RQ1** is addressed through a structured qualitative and conceptual analysis of the policy and regulatory landscape governing cross-border cost-sharing in offshore electricity infrastructure. This includes an examination of the recently published EU Grids Package, the existing EU cost–benefit allocation framework, and a targeted literature review of academic contributions on cross-border cost-sharing mechanisms. These insights are complemented by a graphical analysis of a stylized two-zone coupled electricity market, in which the effects of interconnector expansion and additional offshore wind deployment are visually assessed. Together, it is made clear how costs, benefits, and risks are generated, distributed, and governed under existing and proposed mechanisms.

Literature review focuses on developing a comprehensive understanding of the context surrounding cross-border cost-sharing. However, given the gaps in the academic literature identified in chapter 2, additional insights are drawn from practical sources, including discussions with experts, past conferences held by the NSEC and the OTC[3] (only as guidance for further research and not directly supportive material), ministerial reports, and consultancy publications. These sources are typically more closely connected to real-world developments and help ensure that the research does not remain confined to purely

[3]These workshops bring together energy ministries, TSOs, and representatives of the European Commission to collaboratively build upon existing and emerging frameworks for cost-sharing, with a strong regional focus.

theoretical considerations. They also provide valuable insight into how cost-sharing mechanisms function within actual negotiation processes, which is particularly relevant for the interests of the Ministerie van Klimaat en Groene Groei.

**RQ 2 - Under non-cooperative investment conditions, how do different cost-sharing mechanism designs influence the efficiency, fairness, and stability of agreed offshore infrastructure expansion outcomes?**

To answer **RQ 2**, the thesis develops a comparative analytical framework based on a two-country partial-equilibrium model of offshore wind and interconnector expansion. Electricity spot markets are represented using linear supply and demand curves, allowing closed-form solutions for flow and consumption. The model accounts for uncertainty in market conditions by evaluating multiple deterministic operating regimes (e.g., import-constrained, export-constrained, uncongested), aggregated using weights to obtain expected welfare outcomes. These are used to construct system- and country-level net social welfare surfaces, which serve as the payoff structure of a non-cooperative Nash game in which countries choose expansion levels given their cost allocations and anticipated benefits. The resulting equilibria are compared against the system-optimal benchmark using a unified performance framework measuring efficiency loss and the cost–benefit mismatch.

Each cost-sharing mechanism evaluated represents a specific combination of an *ex-ante* cost allocation rule and optional *ex-post* adjustment instruments, following the recommendations of Willems et al. (2025), Kristiansen, Muñoz, Oren, and Korpås (2018), and Offshore TSO Collaboration (OTC) (2025). Two ex-ante rules are considered: a fixed equal split (50–50) and a benefit-proportional (BP) allocation. These are combined with two optional ex-post instruments: a *Contract for Difference for transmission* ($\mathrm{CfD}_{\mathrm{trans}}$) and a *Contract for Difference for generation* ($\mathrm{CfD}_{\mathrm{gen}}$), the latter inspired by the Bornholm Energy Island hybrid project (TGS 4C Offshore, n.d.). Detailed descriptions of each mechanism are provided in chapter 2.

Three sensitivity analyses are conducted: varying regime probability weights across 14 Dirichlet draws, sweeping CfD strike prices over predefined ranges, and varying unit costs of interconnector and radial infrastructure independently.

**RQ 3 - To what extent can design considerations overcome constraints on implementing the proposed cost-sharing mechanisms?**

RQ3 is addressed through a structured discussion that draws on the quantitative results of Chapter 5 and the cross-cutting insights of section 5.7, and translates them into practical implementation considerations across sections 6.1 and 6.2. The discussion was shaped through a series of consultations with industry stakeholders, including professionals from the Ministerie van Klimaat en Groene Groei and other relevant external experts. These consultations took the form of one-hour meetings in which the model results were presented alongside an explanation of the CfD for transmission and the cross-border implementation of the CfD for generation. The presentations were followed by structured discussions, initiated through the following questions:

- Under what conditions would countries realistically agree to a jointly coordinated offshore expansion?
- When moving from the model to practice, which assumptions become the most critical limitations?
- How sensitive are these results to conditions that the model cannot fully capture?
- What do these findings concretely imply for the design of cross-border cost-sharing agreements and support schemes?

The perspectives and pointers raised during these consultations served as guidance for identifying the most policy-relevant dimensions of the analysis, and not as direct evidential support for any conclusion. All insights presented in Sections 6.1 and 6.2 are grounded in the model results and supported by available academic and grey literature.

## 1.5. Research contributions

This thesis contributes to the academic literature on cross-border cost-sharing for offshore electricity infrastructure along three lines. First, it consolidates the academic literature, EU policy and regulatory landscape, and current industry practice into a single coherent picture. Second, it develops a framework within which multiple existing and proposed cost-sharing mechanisms are evaluated comparatively under identical conditions, addressing the absence of a consistent methodological basis in prior work. Third, and most distinctively, the research moves beyond the question of how costs and benefits should be allocated to the question of under what conditions bilateral agreement is achievable at all by introducing performance criteria to assess mechanisms against that standard.

## 1.6. Report structure

The remainder of this thesis is structured as follows. Chapter 2 reviews the surrounding literature across three complementary bodies of knowledge: it surveys the relevant academic work, examines the EU-level policy and regulatory landscape governing cross-border offshore infrastructure, and introduces the existing and proposed cost-sharing frameworks from the CBCA ex-ante allocation rules and ex-post instruments and identifying where current knowledge and practice fall short. Chapter 3 concretizes the distributional challenge through a graphical analysis of a stylized three-node coupled electricity market, illustrating how the benefits of offshore wind and interconnector expansion spill across borders. Chapter 4 then develops the analytical framework. Chapter 5 presents the simulation results, examining the isolated and combined effects of ex-ante allocation rules and ex-post instruments on investment incentives, welfare distribution, and the scope for bilateral agreement. Chapter 6 interprets these findings, discusses implementation constraints, and situates the results within the broader North Sea cooperation landscape. The thesis concludes in chapter 7 with answers to the research questions and targeted policy recommendations for the Ministerie van Klimaat en Groene Groei. Analytical solutions to the market clearing problem are provided in Appendix A, and additional context relevant for the research has been provided in Appendix B.

# 2

# Literature Review

This chapter consolidates three bodies of knowledge relevant to the cross-border cost-sharing problem in the North Sea: the policy and institutional landscape, the academic literature, and the existing frameworks and instruments for cost allocation. The review is organized to build understanding progressively. It begins with the institutional and collaborative context to establish why cost-sharing has become a pressing and unresolved governance challenge. The academic literature is then reviewed to assess how theory has engaged with this problem and where it falls short. This is followed by a structured overview of the cost-sharing mechanisms that have been proposed or are currently in use, covering both ex-ante allocation rules and ex-post redistribution instruments. The chapter concludes with a unified synthesis of the gaps identified across all three bodies of literature, which together motivate the research design and analytical framework developed in subsequent chapters.

## 2.1. The institutional and collaborative context

Countries of the North Sea region coordinate shared offshore energy ambitions through two key bodies: the Offshore TSO Collaboration (OTC), which supports regional cooperation among transmission system operators, and the North Sea Energy Cooperation (NSEC), which serves as the main intergovernmental framework for coordinating offshore wind expansion and cross-border infrastructure development (North Seas Energy Cooperation and European Commission, 2025). The positions of these bodies on cross-border cost-sharing are reflected in a series of flagship joint statements, summarized in Table 2.1.

**Table 2.1:** Key policy statements on cross-border cost-sharing in the North Sea

| Statement | Year | Key position on cost-sharing | Source |
|---|---|---|---|
| Joint Statement of Ostend | 2025 | Encourages NSEC and OTC to discuss non-binding cost-sharing approaches; welcomes ENTSO-E's cross-border cost-sharing assessment under TEN-E; commits to continuing regional discussions. | North Seas Energy Cooperation and European Commission (2025) |
| Hamburg Declaration of Energy Ministers | 2026 | Endorses a regional approach; calls for a functional cost–benefit sharing framework aligned with benefit allocation; supports joint CfD schemes and exploration of cross-border two-sided CfDs for offshore wind. | Energy Ministers of Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, and the United Kingdom (2026b) |
| Offshore Financing Framework | 2026 | Commits to improving cost-sharing processes for cooperation project sets; identifies joint CfDs as effective instruments; advocates coordinated cross-border two-sided CfD design to lower investment barriers. | North Seas Energy Cooperation (NSEC) and United Kingdom (2026) |
| Hamburg Action Plan | 2026 | Sets concrete timeline: joint cost–benefit sharing methodology by end of 2026; design options for domestic and joint offshore wind CfDs by early 2027. | Energy Ministers of Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, and the United Kingdom (2026a) |

Overall, these policy statements demonstrate a growing recognition among North Sea countries that achieving large-scale offshore wind deployment requires stronger regional coordination and cooperative governance frameworks. In particular, they highlight the increasing importance of joint and cross-border instruments for planning, financing, and supporting offshore energy infrastructure. The discussions around cost–benefit sharing methodologies, as well as the exploration of joint support mechanisms, reflect efforts to ensure that the costs and benefits of cooperation projects are distributed fairly among participating countries. At the same time, policymakers increasingly consider the potential role of cross-border CfD-based instruments in facilitating coordinated project development.

Although the ambitions and objectives are clearly articulated, the specific frameworks and tools required to design the necessary financial instruments, such as cross-border joint CfDs or other cost-sharing mechanisms, remain uncertain. In other words, while the policy goals are well defined, the question of how these arrangements should be implemented in practice remains unresolved.

Within the political and regulatory context of cost-sharing, multiple frameworks, guidelines, and other instruments exist. Although most of these are not inherently designed for the purpose of allocating costs of cross-border assets, they have a role in the playing field.

- **TEN-E Regulation:** The Trans-European Networks for Energy (TEN-E) policy is the EU's framework for integrating national energy systems, enhancing cross-border connectivity, and promoting solidarity and coordinated infrastructure development across Member States (European Commission, 2025f). This legislation outlines the selection guidelines of Project of Common Interest (PCI) status for energy infrastructure projects and facilitates their nomination; making it relevant for assessing whether the same project can have access to different financing channels, such as the Connecting Europe Facility (CEF), depending on the scope of the collaboration model used.

- **Commission Guidance on Cost-Benefit Sharing in Cross-border Renewable Energy Projects:** The guidance outlines design options for cost–benefit sharing in cross-border renewable energy cooperation projects and provides recommendations and best practices, while still allowing Member States flexibility in implementation (European Commission, 2022). Its recommendations centre on grounding the sharing arrangement in a prior societal CBA and applying three principles—fairness, practicability, and reflection of actual costs and benefits—while keeping the set of parties and indicators as limited as possible, with support costs (state-backed subsidy-schemes with the offshore wind farm developer) and RES statistics treated as the core indicators.
- **EU Action Plan for Grids:** Published November 2023, this plan highlights the need to develop the pan-European electricity grid further and faster. One of the ambitious goals is to double cross-border transmission infrastructure until 2030, corresponding to a 64 GW expansion to the current capacity and €584 billion in investments (European Commission, 2023). Additional action points have been laid out to accelerate the implementation of PCIs, improve system-level planning, and introduce regulatory incentives through anticipatory investments and offshore cross-border cost sharing.
- **Renewable Energy Financing Mechanism (RENEWFM):** The RENEWFM, set by the RED II directive of the EU Commission, pools financial contributions from participating EU countries and then allocates funding through a system of competitive tenders for renewable energy projects (CINEA, 2023). The mechanism involves contributing countries, which make voluntary payments into the scheme, and host countries, where the new renewable projects are built.
- **Renewable Energy Directive (RED II and RED III) Cooperation Mechanisms:** The RED II framework establishes cooperation mechanisms to facilitate cross-border collaboration in renewable energy production, enabling Member States to benefit from each other's resource profiles (European Commission, 2025b). Among these, the joint projects mechanism is most relevant to this research: two or more EU countries can co-fund a renewable energy project to meet their targets, with the Commission publishing guidance on cost-benefit sharing for such projects to facilitate mutually beneficial agreements (European Commission, 2022). RED III strengthens this by requiring Member States to establish cooperation frameworks for joint renewable energy projects, and explicitly supports the exploration of cross-border two-sided CfD mechanisms as a tool for coordinating offshore wind support (European Parliament, 2023). A more detailed breakdown of cooperation mechanisms is provided in Appendix B.

## 2.2. EU Grids Package

On the 10th of December, 2025, the European Commission released the latest European Grids Package. The package provides the Commission's view on the current status of Europe's grid development and provides a policy pathway to removing structural bottlenecks in the existing governance frameworks such as the TEN-E regulation and the CBCA (European Commission, 2025a).

The publication comes at a particularly relevant stage of this research as it provides critical insight into how the European Union intends to plan, finance, and allocate costs for energy infrastructure with cross-border impacts. Alignment of the research with these emerging regulatory priorities through addressing knowledge gaps and accounting for forthcoming legislative changes stand to enhance the practical relevance of the research outcomes. With a specific focus on elements of cross-border cost-sharing, aspects of the Grids Package relevant in this context have been provided.

This EU Grids Package's objective is to provide the necessary grounds where collective decisions can be taken to resolve structural issues in EU energy infrastructure planning and implementation- with the ultimate goal of the successful delivery of a genuine Energy Union that enables energy independence, strengthens competitiveness, drives decarbonization, and fosters energy security. This objective is pursued through (Butorac, 2026):

- Simplification of the EU rules on grids
- Integration of EU-level, regional, and national needs
- Development of effective cost-sharing mechanisms for cross-border PCIs

### 2.2.1. Gap-filling role of the EU Commission

The package emphasizes the need for further action to improve coordination across national, regional, and EU-level actors to build an optimized and interconnected grid. To achieve this, a shift from the current legislative frameworks to an EU cross-border energy infrastructure planning framework is proposed. The Commission will develop a comprehensive central EU scenario based on the EU energy and climate targets, and inputs from Member States and other relevant stakeholders.

Energy infrastructure projects proposed by the Member States will be inclined to align with the current and future EU objectives, following a more coordinated and robust identification of needs (European Commission, 2025a). In cases of persistent gaps or lack of agreement among Member States, the Commission assumes a gap-filling role to ensure the delivery of critical grid projects. Under the revised governance framework, the development of critical infrastructure within continentally significant energy ecosystems, which includes offshore wind generation and grid assets in the North Sea[1], is increasingly overseen by a central regulatory authority. This would reduce the scope for unilateral Member State vetoes and exert greater pressure on national authorities to cooperate in regional, cross-border development processes.

A pressing concern in the context of cost-sharing related to the Commission's new gap-filling function is that the Grids Package does not clarify how costs would be allocated if the Commission were to intervene to break a negotiation deadlock and grant approval for a necessary infrastructure project. While the package outlines a general pathway for the practical application of cross-border cost-sharing instruments to a limited extent, it does not establish a clear link between this gap-filling function and the associated cost-sharing mechanisms.

### 2.2.2. Emphasis on cross-border cost-sharing

Fair and transparent cost-sharing is essential to avoid disproportionate burdens on local consumers (European Commission, 2025a). The EU Grids Package aims to provide more transparency, certainty, and fairness in the way costs and benefits are assessed and shared, with the Connecting Europe Facility (CEF) serving as the primary funding instrument for implementing the TEN-E legislation (European Climate, Infrastructure and Environment Executive Agency (CINEA), 2025).

As noted by European Commission (2025e), the TEN-E provides Member States with a structured regulatory framework governing cost allocation and the treatment of investment risk. However, difficulties in reaching agreement when non-negligible benefits accrue to non-host countries are identified as a key reason for the low rate of implementation of cross-border infrastructure, which is a problem likely to intensify as markets become further integrated. The proposal's stakeholder consultation confirms this diagnosis, with a majority of stakeholders agreeing that the current framework (European Commission, 2024) is not fit for purpose, that the CBCA should be extended to non-host Member States on a benefit-proportional basis, and that project bundling should be used to facilitate cost-sharing discussions across a broader set of beneficiaries.

In response, European Commission (2025e) introduces Article 17, which establishes that

[1] Annex I of the TEN-E Regulation provides a list of these regions, which includes the North Sea.

cost allocation must be grounded in net-benefit distribution, that ex-post adjustment mechanisms must complement ex-ante allocations, and that any Member State receiving 10% or more of a project's estimated benefits must participate in the cost allocation process. The full breakdown of Articles 15, 16, and 18 is provided in subsection B.2.3. More broadly, the proposal emphasises that costs should be borne by all users of the infrastructure proportional to their benefits, and that allocations should be grounded in a harmonized CBA and CBCA framework. However, no specification of how the ex-post mechanisms should be designed, or how the CBA framework should be adjusted in practice, is provided. This leaves the methodological core unresolved.

### 2.2.3. CEF and PCIs in the context of cost-sharing

CEF eligibility conditions through the assignment of the PCI status, inherently emphasizes the cross-border significance of infrastructure projects, thereby incentivizing Member States to engage in collaborative investments that ensure a fair and effective distribution of costs and benefits. According to European Commission (2025a), the Grids Package aims to enable the bundling of PCIs (and PMIs) that would facilitate cost-sharing discussions between Member States by fostering win-win solutions, reducing risks and transaction costs in negotiations, and increasing the likelihood of implementation (European Commission, 2025a).

CEF can be expected to be increasingly regarded as a key enabler for financing and facilitating the development of offshore wind energy and associated grid infrastructure. The Netherlands—along with other North Sea countries—may become more willing to take on the additional bureaucratic workload of applying for a PCI status and increasingly design or prioritize projects that qualify under this status (Ministerie van Klimaat en Groene Groei, 2025a). This would imply the deliberate proposal of projects with substantial cross-border impacts (exceeding 10%) by design, even where such projects are located entirely within Dutch territory. Adopting this approach has the potential to reduce the overall costs of renewable energy integration and grid expansion in the North Sea, not only for The Netherlands but also for all participating countries.

## 2.3. Academic foundations

Within the reviewed literature, Nylund and Egerer (2014) and Kristiansen et al. (2018) both examine the application of cooperative game theory—specifically the Shapley Value (SV)[2]—to cost-sharing problems in the North Sea context.

**Nylund and Egerer (2014)** compare the proportional allocation method, which represents the multilateral regional cost-sharing framework used in CBCA, with the traditional equal-partition principle, which applies only in bilateral settings. Their analysis does not assume that transmission investments are predetermined; instead, investments proceed only when the net payoff for all participants is positive. In the multilateral (regional) case, they find that average welfare increases for all participating countries.

**Kristiansen et al. (2018)** adopt a similar analytical approach, but with a key distinction: transmission investments are treated as given, and generation investments adjust in response. Their study evaluates a predefined portfolio of three planned North Sea interconnections—NordLink (NO–DE), Viking (DK–GB), and North Sea Link (NO–GB). Although the Netherlands is not a hosting country for these assets, its welfare outcomes are included. The authors first compute the Shapley Value by applying cooperative game theory to all possible coalitions among the six countries in their network, under two cost-sharing rules: equal partition and positive net-benefit differential (proportional allocation method of Nylund and Egerer (2014)). They then propose the use of CfD for transmission based on a set of bilateral strike price contracts as an instrument to implement the Shapley Value allocations. Each country would either receive from or contribute to an ITC fund

[2] The Shapley Value is a cooperative game-theoretic solution concept that assigns a unique allocation to players in a coalitional game (Narahari, 2012).

based on the strike price agreements. More information is provided in subsection 2.4.3.

**Konstantelos et al. (2017)** explores the underlying reasons for the lack of commercial interest in the incremental development of an integrated North Sea electrical system, specifically concerning the formation hybrid structures with a focus on asymmetric benefit allocation. Questions relevant to understanding the investment costs, benefits, and risks—and how these relate to the type of offshore infrastructure developed—addressed by this study include:

- How substantial is the benefit of integrated solutions?
- Is it riskier to build integrated networks compared to conventional radial connections?
- What are the regulatory issues that may be currently prohibiting the development of offshore integrated networks?
- To what extent is asymmetric cost/benefit allocation a barrier to the development of integrated projects?

They employ multiple case studies based on real planned projects that are likely to be carried out: German Bight (NL, DE, DK), UK-Benelux (UK, BE, NL), and UK-Norway (UK, NO). For each case, a radial-only setup is compared to an hybrid-based setup. They conclude that in all cases, the integrated network is more beneficial than its conventional counterpart. For efficient allocation of costs and benefit, their main recommendation is to consistently apply the Positive Net Benefit Differential mechanism[3] as a starting point for negotiations. Finally, they suggest that the rule for compensation between stakeholders should be investigated further; specifically the balance that needs to be struck between theory and political feasibility.

**Hogan (2018)** considers the issue of optimal cost allocation for transmission assets within a fully domestic scale (non-cross-border assets with only local actors of load and generation). They attempt to create an efficient investment framework based on the beneficiary-pays principle, which seeks to maximize the net present value of total benefits minus total costs, as an alternative to the traditional cost socialization (load pays fixed rate via national tariffs). The paper describes an analytical method for ex-ante determination of costs and benefits of transmission capacity expansion using the supply-demand curves of two price zones.

The following findings were identified to be relevant to the thesis research:

- The power flow model, which allocates costs of individual lines by tracking change in power flows on the transmission lines, does not provide a good theoretical foundation for estimating benefits.
- Estimating shares of benefits is easier than estimating the benefits.
- Without a beneficiary-pays principle it would be challenging to sustain a mix of voluntary and mandated transmission investments or to create efficient incentives for generation and load.
- For small incremental expansion in transmission capacity that have negligible effect on expected prices across locations, there would be incentives for efficient voluntary investment where the benefits would be captured by incremental financial transmission right (FTRs). They claim that a greater scale of investment, usually in lumps, voluntary investment is limited as there may be inadequate value in the resulting FTR to support the investment[4].
- Bilateral contracts redistribute costs and benefits in ways that can affect incentives for other transmission expansions. Entering into an FTR-type contract that is privately beneficial may reduce the parties' willingness to support additional projects, because

[3] The proportional-to-benefits payment scheme where countries in a net-positive outcome compensate those that are in a net-negative as defined by Willems et al. (2025).

[4] Due to price conversion across regions, the resulting FTR would not be able to provide the necessary value.

the net benefits they receive from the contract may be lower than what they would have obtained had they not entered into it in the first place.

This paper is targeting the context of the US electricity markets, which has a distinct structure compared to the Dutch/European electricity markets. In some ways, it would be possible to realize similarities between the nodal pricing structure in the US and the territorial price zones in the EU[5].

**Loureiro, Claro, and Fischbeck (2019)** develop a cooperative game-theoretic framework for determining optimal cross-border transmission investments in market-coupled regions. Their Interconnection Transmission Expansion Problem for Market Coupled Regions models two TSOs that negotiate the level of interconnection capacity using either Nash–Coase bargaining (with compensations) or Nash bargaining (without compensations). Markets are represented using linear supply and demand curves for each region, while uncertainty in market conditions is incorporated through multiple operating states weighted by their probability of occurrence over a representative year. This probabilistic treatment allows expected social welfare gains from trade and investment to be calculated under varying import–export and price-differential conditions.

A key contribution of the study lies in linking optimal interconnection sizing to a fair-share cost allocation rule based on incremental net social welfare gains. Under Nash–Coase bargaining, the decentralized solution coincides with the centralized social welfare optimum, with net welfare gains equalized between regions through compensatory transfers. When compensations are restricted, however, investment levels may be lower and cost shares capped, potentially leading to suboptimal outcomes.

Applied to the Iberian electricity market (Portugal–Spain), the model produces interconnection capacity estimates consistent with real-world investment plans. The results highlight how asymmetric welfare gains, bargaining power, and transmission costs shape cost allocation patterns—ranging from full importer-financing (including potential compensations) at low costs to exporter-dominant cost shares at higher cost levels.

The study is particularly relevant to the thesis as it provides a formalized bargaining-based alternative to centrally determined cost-benefit allocation and explicitly distinguishes between ex-ante cooperative surplus-sharing and constrained bargaining settings. Its use of probabilistically weighted linear market representations also aligns closely with the analytical structure adopted in this thesis.

## 2.4. The cost sharing framework

The large-scale deployment of offshore wind and cross-border transmission infrastructure in the North Sea requires effective mechanisms for allocating costs, benefits, and risks among participating countries. While the European Union has established a framework for cross-border cost allocation (CBCA), existing approaches remain limited in scope and struggle to accommodate the increasing complexity of these discussions. After briefly contextualizing the institutional process linking Cost-Benefit Analysis (CBA) to the CBCA, this chapter introduces and formalizes the cost-sharing mechanisms considered in this study: the ex-ante allocation rules and the ex-post redistribution instruments evaluated in the model for both transmission and generation assets.

Additional mechanisms identified in the literature but not analytically evaluated, including the territorial split, inter-TSO compensation (ITC), congestion income distribution (CID), injection charges, and EU-wide tariff proposals, are also surveyed to situate the study within the broader policy and academic debate.

[5] Hogan (2018) models consumers (load), generators, and third-party merchants as the contributing and receiving parties in transmission investments. While such an arrangement is legally not possible under most European regulatory frameworks, the underlying method and analytical insights remain applicable if the actors are reinterpreted to represent cross-border TSOs and other relevant entities.

### 2.4.1. From CBA to CBCA

This section briefly provides context on the evolution of cost-sharing processes during the stages preceding negotiations and the earlier steps that determine cost and benefit assessments. All information provided is based on Willems et al. (2025)'s description of the process. The step-by-step process, from the development of scenarios representing future energy system expectations to the conduct of a cost-benefit-analysis (CBA), and the final allocation of costs through CBCA, is illustrated in Figure 2.1.

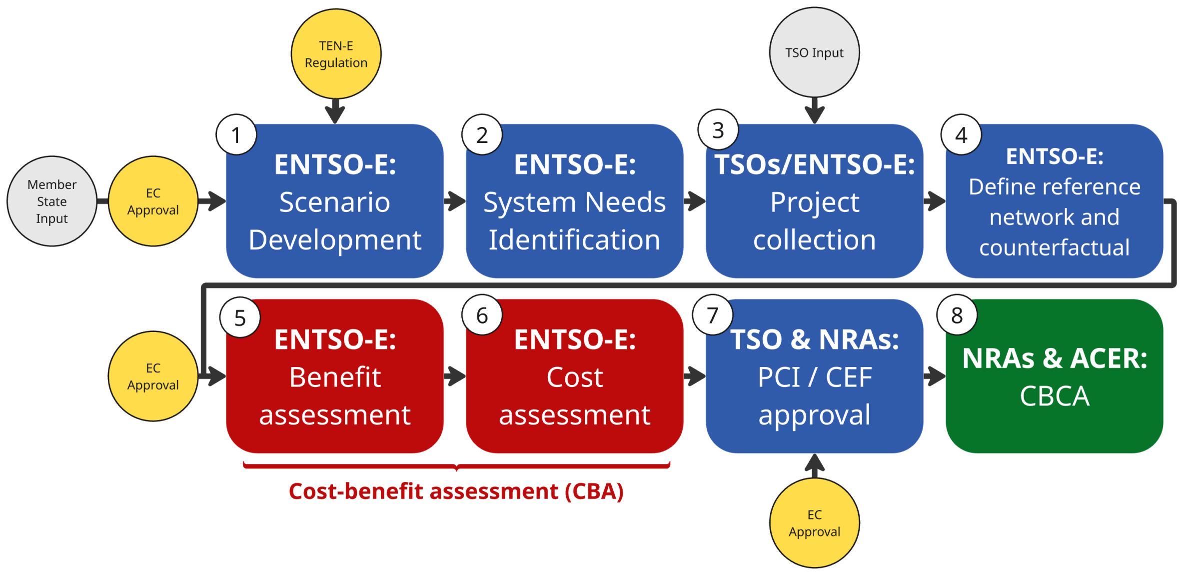



**Figure 2.1:** The EU energy infrastructure planning and CBA process: from scenario development to cost allocation

Individual elements of this process are described as the following:

1. **Scenario development -** Every two years, ENTSO-E is mandated under the TEN-E regulation to develop plausible scenarios for the future European energy system which are characterized by generation portfolios, demand forecasts, and inter-country flows.
2. **System needs identification -** Based on scenario development results, market/network modeling identify specific additional network capacity needs.
3. **Project collection -** TSOs (and potentially other infrastructure developers), propose projects to fill the gap (network capacity needs) and submit them to the TYNDP for CBA assessment.
4. **Reference network and counterfactual -** CBA starts by defining a forecasted state of the transmission network that includes all proposed projects (and ones under development) with a high likelihood of completion by the simulation year. The project's marginal contribution is assessed by comparing the network with the project (factual) and without it (counterfactual). This approach is done singularly for each project, without assessing a collective contribution to net gains and losses, with two distinct approaches depending on whether a project is already in the reference network or not:

   - Take-Out-One-at-a-Time (TOOT): Used for projects already in the reference network; removes the project to form the counterfactual.
   - Put-In-One-at-a-Time (PINT): Used for projects not in the reference network; adds the project to form the factual.

5. **Benefit assessment -** Benefits are assessed based on the key indicators presented in Table 1.1.
6. **Cost assessment -** Independent to scenario-based variations, project cost assessments include CAPEX of development, construction and commissioning with a discount factor of 4% per annum to the common reference year.
7. **PCI status and CEF access -** A positive CBA grants the right for the project to apply for a PCI status, which is a requirement to be able to access the CEF EU financial support as per the TEN-E regulation.
8. **CBA to CBCA:** Results from the CBA feed into the cost-sharing negotiations between Member States, the CBCA. Willems et al. (2025) notes a clear disconnect between the EU-level planning (essentially all previous steps) and the bilateral negotiations that determine what gets built. The CBA informs the negotiation but does not bind it: Member States retain full discretion over whether and how to translate the assessed costs and benefits into an agreed cost-sharing arrangement.

**Costs to be considered**

Offshore TSO Collaboration (OTC) (2025) presents four main types of costs, each with varying levels of impact and temporal allocation as represented in Figure 2.2. Table 2.2 provides a description of the individual cost components.

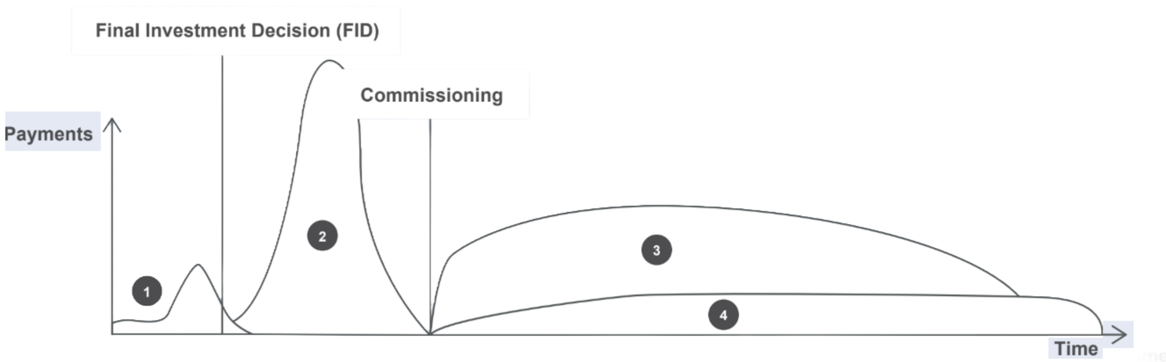



**Figure 2.2:** Payment timeline for cross-border cost-sharing processes (Offshore TSO Collaboration (OTC), 2025)

**Table 2.2:** Different cost components and their consideration in cost sharing

| Nr. | Cost type | Description | Consideration in cost sharing |
|---|---|---|---|
| 1. | Development Expenditures (DEVEX) | Pre-investment costs incurred before the final investment decision, including feasibility studies and early contractual arrangements. | Generally covered by the host countries, though the cost of seabed surveys can present a barrier to early commitment. |
| 2. | Capital Expenditures (CAPEX)* | Expenditures related to building and commissioning the physical infrastructure, including procurement of cables, converters, and turbines. | The primary subject of cross-border cost allocation. |
| 3. | Capital payments (CAPEX)* | Financing costs arising from the capital mobilised to fund the investment. | The primary subject of cross-border cost allocation. |
| 4. | Operational Expenditures (OPEX) | Ongoing costs of operating the asset after commissioning, covering both fixed and variable maintenance expenditures. | Only fixed operations and maintenance costs fall within scope; variable and other operational costs are *currently* excluded from the cost-sharing framework. |

* Nominally, onshore reinforcements are not considered in scope of the CAPEX cost sharing.

### 2.4.2. Ex-ante cost sharing mechanisms

Upon reaching the FID stage, assets with cross-border relevance are expected to have an agreement on sharing keys- that is the percentage each country agrees to contribute to the investment costs. For the different types of identifying sharing keys, Willems et al. (2025) is used as the textbook guideline (CBCA). Two methods for allocating sharing keys are suggested based on the CBCA framework. Other proposed and current methods include the territorial split, the Inter-TSO-Compensation (ITC), Congestion Income Distribution (CID), injection charges, the EU-wide tariff, and the regional savings account.

**CBCA - Equal partition (50-50 split)**
The equal partition principle (50-50 split), where each country contributes for half of the total investment costs and is entitled to half of the congestion rents (for a transmission project). It is a preferred allocation due to the simplicity in its design.

**CBCA - Benefit-proportional**
Willems et al. (2025) proposes the proportional-to-benefits method (complementary to the existing CBCA framework) where the lower-benefiting countries are compensated by the higher-benefiting- ultimately eliminating the benefit-asymmetry by guaranteeing that both countries agree to build socially optimal investments as an alternative to the simple territorial-split or the equal-partition. In simple terms, the higher a country benefits from expanded offshore transmission capacity, the more it will have to contribute or compensate.

**Territorial split**
One of the common cost sharing principles in the past has been the territorial principle, where each TSO pays for the infrastructure within their respective geographic borders, valued primarily for its simplicity in design.

This method does not always translate to a fair allocation, which may deter voluntary international collaboration. A resource-rich country exporting lower-cost electricity to a nearby importing region, for instance, may reap asymmetric (or even net negative) benefits relative to its cost contribution (Willems et al., 2025). More fundamentally, the benefits of expanded offshore transmission capacity are not limited to hosting Member States but spill over to non-hosting countries as well, which the territorial principle does not account for. This misalignment is further compounded in the North Sea context: under the high wind energy scenario of PROMOTioN Consortium (2020), some cross-EEZ infrastructure enrichment was deemed necessary, directly highlighting that the territorial split is ill-suited to the future vision of the North Sea.

These shortcomings are expected to become more pronounced as the pan-European electricity market becomes further interconnected and the grid increasingly electrified. European Commission (2024) therefore calls for the development of more advanced collaboration tools and frameworks to ensure that regional ambitions reflecting a socially optimal system perspective are not compromised. For these reasons, the territorial-partition principle is not tested within the analytical framework of this research.

**Inter-TSO-Compensation (ITC) and Congestion Income Distribution (CID)**
Alongside the CBCA, ACER-CEER presents two additional fragmented mechanisms that enable the sharing costs and benefits: inter-TSO-compensation (ITC) (outdated (Povh, 2025)) and congestion income distribution (CID) (inadequate to drive cross-border investments (Povh, 2025)). ACER-CEER claim that these two frameworks and the CBCA fall short in adequately addressing the equitable sharing of offshore transmission infrastructure costs and benefits.

**Injection charges**
Hirth, Eicke, Maksimova, Maurer, and Weiß (2025) investigated the potential of recovering grid infrastructure costs via injection charges (generators' tariff for feeding power to the

grid) and concluded that this only works if there is a net increase in the wholesale price and if the country is a net exporter. In such scenarios, foreign consumers will contribute to the recovery of domestic infrastructure investment costs. There are concerns regarding the practical applicability of this measure and will likely not yield a region-wide socially optimum outcome if only applied at a national or regional level (Hirth et al., 2025).

**EU-wide tariff and regional savings account**

An EU-wide tariff (Willems et al., 2025) and the regional saving account (European Commission, 2024) are also proposed. The EU-wide tariff would see the subsidization of the offshore infrastructure projects in the North Sea by all (or select groups) of consumers from the entire EU regardless of which EEZ the project is constructed. This would imply the recognition of infrastructure projects to be of continental relevance, going even beyond a PCI/PMI status. On the other hand, the regional savings account would entail the collection of congestion revenues from offshore transmission assets in a collective pool from all countries and TSO in the North Sea area. Funds collected in this account would later be used for financing new infrastructure projects here. However, their applicability is an open question.

### 2.4.3. Ex-post redistribution mechanisms

Post FID, ex-post instruments can be used to redistribute benefit surpluses across different stakeholders (Willems et al., 2025). In this analysis, three instruments are investigated: congestion rent, which is not a redistribution mechanism in itself but becomes one through the sharing key that determines how it is divided between countries, and the use of CfDs for transmission and generation, which are both seen as promising tools to facilitate cross-border cost-sharing discussions.

Even after the publication of the EU Grids Package, which specifically highlights the need for ex-post adjustment mechanisms (European Commission, 2025a), there is no European guiding framework dedicated to cross-border CfDs and only one practical example of a cross-border CfD utilized under cost-sharing objectives (The Bornhelm Energy Island - Germany & Denmark) (TGS 4C Offshore, n.d.).

**Cross-border CfD for transmission**

The *cross-border CfD for transmission* is a CfD-based ex-post adjustment mechanism proposed by Kristiansen et al. (2018), implemented through a set of bilateral strike price contracts and a cooperative interconnection fund. It is not a confirmed, established, or formally proposed instrument within existing EU regulation, but aligns with the policy recommendation by OTC (2025b) and the suggestions of European Commission (2025a), where each country pays proportional to their import based on cross-country flow measurements.

Under this mechanism, the costs associated with new transmission interconnections, along with congestion rents, are first allocated using a conventional ex-ante approach (such as the 50-50 split or the benefit-proportional). Subsequently, a coordinating body (e.g., ENTSO-E or ACER) determines the necessary side payments to ensure a fair distribution of net benefits in line with the Shapley Value (SV), which is a cooperative game-theoretic concept that allocates net benefits to each country in proportion to its average marginal contribution across all possible subsets of cooperating countries. These side payments then serve as the foundation for establishing a set of strike price contracts, structured as contracts for difference, between a central clearing fund — through which cross-border side payments are settled — and the participating countries. Willems et al. (2025) note that this approach is suitable primarily for defined interconnector transmission project sets within a sea-basin CBA.

Kristiansen et al. (2018) implement this redistribution through a central interconnection fund to which all participating countries are contractually linked. Each country $A$ is assigned a fixed strike price $\lambda_A^{trans}$, which is not a trading price, but a reference level representing what that country ”should” receive per unit of net cross-border flow, based on the desired allocation of net benefits. Countries continue to trade at prevailing spot prices; the fund then settles the difference. When the spot price falls below the strike price, country $A$ receives a compensating payment from the fund — it received less from the market than its agreed entitlement. When the spot price exceeds the strike price, country $A$ pays into the fund — it received more than its entitlement. This settlement occurs for every interconnection $l \in L_A$ linked to country $A$, in every time period $t \in T$, accounting for the direction of flow and line losses $loss_l$. Aggregating and discounting via annuity factor $a$, the total side payment for country $A$ is:

$$SP_A = a \sum_{l \in L_A} \sum_{t \in T} (\lambda_A^{trans} - \lambda_{l,t}^{spot}) \cdot \left( f_{l,t}^{exp} - f_{l,t}^{imp}(1 - loss_l) \right) \tag{2.1}$$

Here, $a$ is an annuity factor used to discount payments over the planning horizon, and $f_{l,t}^{exp}$ and $f_{l,t}^{imp}$ are non-negative export and import flows. A positive $SP_A$ means country $A$ is a net receiver from the fund; a negative $SP_A$ means it is a net contributor. The sign combinations arising from this expression are exhaustive: a country may be in either a net export or net import position, and the spot price may lie either above or below the strike price. The direction of the resulting side payment is determined mechanically by these two conditions — it is simply the arithmetic consequence of the chosen contractual strike price relative to realized market outcomes.

By calibrating each country's strike price to a target allocation — such as the Shapley Value — the mechanism ensures the fund remains budget-balanced across all participating countries $c \in \mathcal{C}$:

$$\sum_{c \in \mathcal{C}} SP_c = 0 \tag{2.2}$$

**Correcting ex-ante allocations through CfD for transmission**

Kristiansen et al. (2018) show that purely ex-ante allocation rules can lead to substantial mismatches between a country's allocated share of costs and benefits and its actual contribution to the system, resulting in over- or under-compensation and weakened incentives to cooperate. They argue that incorporating an ex-post corrective mechanism through side payments improves upon this by aligning realized net benefits more closely with each country's contribution, thereby enhancing fairness and making cooperative agreements more stable and acceptable.

Kristiansen et al. (2018) employ this CfD-based instrument to achieve an optimal allocation of net costs consistent with a Shapley Value (SV) allocation. Starting from an initial, potentially imperfect ex-ante allocation—such as a 50–50 split—the mechanism introduces corrective annual side payments that adjust the distribution of net benefits over time. Aggregated over the full lifetime of the asset (e.g., a 30-year horizon), these side payments effectively "correct" the initial allocation by compensating countries whose assigned costs exceed the benefits they realize, and vice versa[6]. This is represented in Figure 2.3, where the left panel illustrates the deviation of the initial ESP-based[7] allocation from the SV benchmark, while the right panel shows the corresponding side payments required to eliminate these discrepancies and achieve the fair allocation.

[6]The 50-50 split allocates costs equally regardless of each country's actual contribution to the cooperative agreement. This can result in systematic over- or under-compensation. The Shapley Value corrects for this by allocating net benefits in proportion to each country's average marginal contribution across all possible coalitions, thereby rewarding countries according to the value that would be forgone were they to withhold cooperation. For instance, a country that can veto a highly valuable interconnector receives a correspondingly larger share than one whose non-participation would cause little loss.

[7]ESP is the equal-share-principle, another name for the 50-50 split.

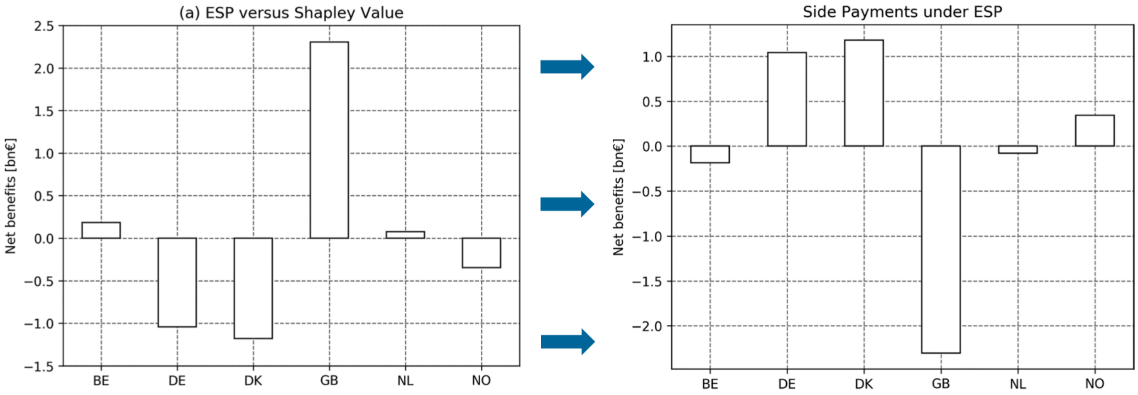



**Figure 2.3:** Comparison of net benefit allocations under the Equal Share Principle (ESP) (i.e. 50–50 split) and the Shapley Value (SV), and the corresponding corrective side payments. The left panel shows the deviation of ESP-based allocations from the SV benchmark, while the right panel presents the side payments required to reconcile these differences. Positive values indicate overcompensation relative to the SV (left) and net receipts (right), whereas negative values indicate undercompensation and required payments.

To achieve this desired allocation, the bilateral contract strike prices are calibrated by backtracking from the SV-based outcome, such that the resulting payments replicate the desired distribution of net benefits. This approach, however, relies on the assumption of perfect information and serves primarily to demonstrate that a mechanism can, in principle, achieve an efficient and fair allocation.

Crucially, the strike price values themselves carry no intrinsic economic meaning. They are not negotiated prices reflecting willingness-to-pay or cost-of-service, but are instead back-calculated from the desired SV-based allocation. Given knowledge of expected flows and prices over the full planning horizon, a strike price can always be found that produces exactly the required side payment. The mechanism is therefore best understood as a device that converts a known target redistribution into an equivalent set of flow-contingent financial transfers.

Crucially, the strike price values themselves carry no intrinsic economic meaning. They are not negotiated prices reflecting willingness-to-pay or cost-of-service, but are instead back-calculated from the desired SV-based allocation. Given knowledge of expected flows and prices over the full planning horizon, a strike price can always be found that produces exactly the required side payment. The mechanism is therefore best understood as a device that converts a known target redistribution into an equivalent set of financial transfers that scale with actual cross-border electricity flows. This grounds the redistribution in realized market outcomes rather than predetermined fixed payments. Flows are the natural settlement basis because the welfare gains from interconnection materialize through them: the greater the volume of cross-border exchange, the greater the realized price convergence and the associated benefit.

In the present study, the CfD mechanism is implemented in a simplified and imperfect manner. Since calibrating strike prices to a predetermined outcome requires perfect foresight over a multi-decade planning horizon, which would be an assumption that is not operationally feasible, the contractual strike prices are instead chosen exogenously. This reorients the analysis from a calibration problem to a robustness problem: rather than asking what strike price would achieve a desired or ideal outcome, the study examines how welfare and investment incentives respond across a range of strike configurations. This framing is directly motivated by current practice: Offshore TSO Collaboration (OTC) (2025) propose the use of observed cross-border power flows as the settlement metric for ex-post cost-sharing adjustments, on the grounds that flow-based payments reflect actual energy use and benefit realization. Understanding how outcomes vary across strike configurations is therefore not merely a modeling choice, but a policy-relevant question for the parties actively designing these instruments.

**Cross-border CfD for generation**
A CfD for generation assets involves the payment of the gap between the spot price the OWF participates in and the agreed-upon strike price. This is the already-commonly used across EU support scheme for offshore wind as illustrated in Figure 2.4, here extended to a cross border setting. As illustrated in Figure 2.5 and Figure 2.6, the two-sided generation CfD in this study operates through financial transfers between the offshore wind farm (OWF) operator and the government-representative-body[8] of the two countries, which are then reflected in country-wide surpluses according to the cost-sharing rule.

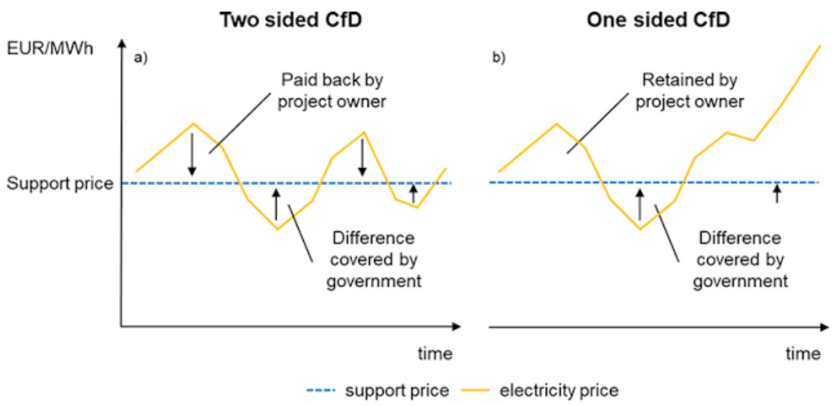



**Figure 2.4:** Illustration of the working principle for a CfD support scheme (courtesy of Đukan, Keles, and Kitzing, 2025)

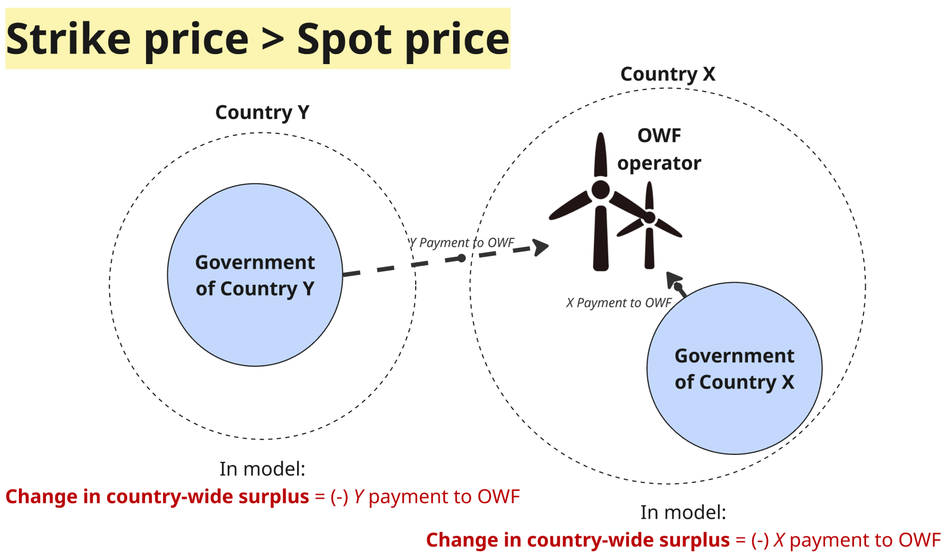



**Figure 2.5:** Generation CfD transfer between countries through the offshore wind operator when the CfD strike price exceeds the spot price.

[8]This is the Energy Ministers in real-world transactions, excluding other public organizations that handle the actual flow of cash. However, budgeting for CfDs is done by the Energy Ministries.

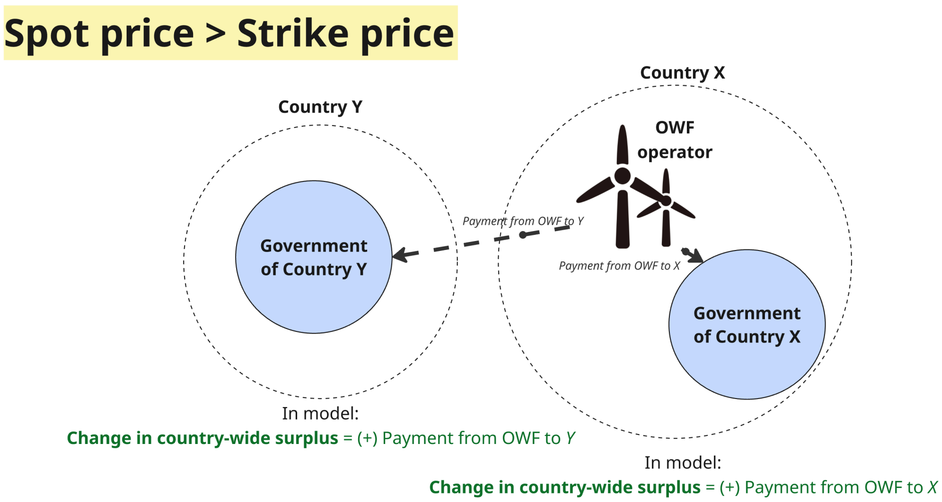



**Figure 2.6:** Generation CfD transfer between countries through the offshore wind operator when the spot price exceeds the CfD strike price.

As shown in Figure 2.5 and Figure 2.6, two cases arise. When the strike price exceeds the spot price (top panel), both governments compensate the OWF operator for the shortfall relative to the agreed strike level, each contributing according to their cost-sharing key $\alpha_n$. Both Country $x$ and Country $y$ therefore register a negative change in their country-wide surplus, as both are net payers to the OWF operator. When the spot price exceeds the strike price (bottom panel), the direction reverses: the OWF operator pays back the difference above the strike level to each government according to the same sharing key. Both countries then register a positive change in their country-wide surplus, receiving clawback payments from the OWF operator.

**Congestion rent**

When electricity flows across an interconnector between two price zones, price differences arising from capacity constraints generate congestion rent. This is the revenue collected by the TSO(s) operating the interconnector equal to the price differential multiplied by the flow across the constrained link. As outlined by ACER (2021) for the Congestion Income Distribution (CID) methodology, it is standard practice to share this revenue across the TSOs at both ends of the interconnecting asset, making congestion rent a natural instrument for redistributing benefits between countries.

## 2.5. Synthesis: gaps in knowledge, policy, and frameworks

The literature review concludes that although cross-border allocation of costs for cross-border assets, there is limited research into allocation-structures under scenarios where both offshore wind interconnectors are shared. There is also no methodological consensus. Various approaches have been seen across the existing literature including scenario-based modeling of physical electricity networks in the North Sea, and use of Shapley-value-based collaborative game theory for determining allocation keys (and expansion outcomes). The literature review identified a key gap in the absence of a consistent analytical framework capable of systematically evaluating existing and proposed cost-sharing mechanisms while extracting generalizable insights. Much of the existing work remains tied to specific project (or project set) configurations and detailed grid models, limiting the transferability of conclusions.

The thesis research addresses a part of this methodological gap by evaluating past, existing, and proposed cost-sharing mechanisms within a single analytical framework. Among the reviewed literature, only OTC (2025a)[9] adopt a comparable approach, but with notable limitations: their analysis assesses only a single ex-ante cost allocation with three variants incorporating CfD-based ex-post adjustments[10], and the sole quantitative indicator of "performance" is the magnitude of the annual correction required between countries. This thesis advances the state of knowledge by examining a broader set of mechanisms and by developing additional performance metrics that capture not only cost and benefit distribution via the *mismatch* metric, and the investment efficiency via the *efficiency loss* metric. More detail is provided in chapter 4.

The same OTC (2025a) note that their quantification of annual ex-post CfD settlement amounts relies solely on financial import–export data, even though alternative approaches—such as analyzing changes in socio-economic welfare (SEW) or congestion income—could also be used. These alternatives, however, remain unexplored. This methodological gap is partially addressed by explicitly accounting for congestion rents (i.e., income arising from network congestion) and integrating them into a net SEW definition[11]. However, this methodological gap is not fully resolved, as the analysis does not incorporate real operational data, as originally recommended by OTC (2025a).

Konstantelos et al. (2017) also emphasize the need to balance theoretical analysis with political feasibility, noting that academic research on offshore grid development can become disconnected from the realities shaped by international politics and national agendas. The analytical results of this thesis are complemented by qualitative insights gathered through engagement with internal and external industry stakeholders — including multiple meetings with policy advisors at the Ministerie van Klimaat en Groene Groei and participation in the OTC–NSEC workshop held on 26 March 2026. These inputs are not treated as standalone evidence or a basis for independent conclusions, but serve as contextual support to inform the interpretation of model results and enrich the broader discussion.

The literature review also revealed several key respects where no study has taken an approach comparable to this thesis. In particular, no existing work examines non-host participation in (physically) fully domestic infrastructure investments (i.e. radial configuration) and considers the interdependent nature of the benefits arising synergistically between generation and transmission assets under a shared cost-sharing framework. Although the approach adopted in this thesis does not restrict the applicability of its results to any specific grid configuration (e.g., radial, cross-border radial, or hybrid), the greatest added value is observed when non-host participants are included, which generally corresponds to radial or cross-border radial configurations. Adjustments to the analytical framework—primarily through the inclusion of offshore bidding zones—hybrid configurations could be accommodated but are relegated to future work.

Likewise, the review found no discussion of a negotiation space that characterizes the feasible region for collaborative investment, moving beyond CBAs and cost-benefit allocations to provide insight into the conditions under which cost sharing becomes mutually acceptable.

While the TEN-E Regulation and its CBCA mechanism were designed to align cost-bearing with benefit-receiving across Member States, both fall short in practice. The majority of CBCA decisions since 2013 have defaulted to the territorial principle (more information provided in subsection 2.4.3), with fewer than 30% setting actual cross-border payments (ACER – European Union Agency for the Cooperation of Energy Regulators, 2023). This reveals that the TEN-E's legislative intent has not translated into outcomes where costs follow benefits across borders, in other words, redistributive outcomes.

According to ACER – European Union Agency for the Cooperation of Energy Regulators

[9]OTC: Offshore TSO Collaboration

[10]Subsection 2.4.3 provides further detail into these and other relevant framework and tools.

[11]Net socio-economic welfare refers to socio-economic welfare that, in addition to the baseline surplus-based SEW (consumer and producer surplus), incorporates congestion rents and the effects of relevant transfer mechanisms.

(2023), the cost-benefit analyses (CBA) underpinning these decisions are highly sensitive to scenario assumptions, where different scenarios can yield opposite outcomes. In negotiations influenced by the surrounding politics, this uncertainty tends to produce the least redistributive result rather than the most efficient one. Structurally, the CBCA is further constrained to transmission CAPEX only, requiring generation and transmission costs to be assessed separately (ACER – European Union Agency for the Cooperation of Energy Regulators, 2023). This is an artificial boundary that blockades the integrated view needed to capture the interdependency between benefits of expanding transmission and generation infrastructure, which is further exacerbated with two distinct funding lines within CEF for the two types of assets. Taken together, the TEN-E's reliance on voluntary agreement and the CBCA's territorial inertia, scenario-driven deadlock, and narrow scope leave the cost-sharing problem for cross-border offshore infrastructure largely unresolved (Povh, 2025).

On the other hand, the EU Action Plan for Grids (European Commission, 2023), the RENEWFM (CINEA, 2023), and the RED cooperation mechanisms (European Commission, 2025c) each fall short of resolving the cost-sharing problem for offshore electricity infrastructure. The Action Plan identifies the need for offshore cross-border cost sharing as a regulatory priority (European Commission, 2023) but stops short of providing an operational allocation framework. The RENEWFM links non-host country contributions to renewable energy statistics rather than to the infrastructure benefits actually received (CINEA, 2023) making it potentially ill-suited for transmission cost allocation, particularly since the mechanism was not originally designed to finance transmission infrastructure. According to Panny and del Río (2025), the RED cooperation mechanisms, despite offering joint projects and joint support schemes that could in principle accommodate offshore wind cooperation, have in practice been overwhelmingly dominated by statistical transfers, which is the least ambitious instrument, while more structural mechanisms have barely materialized due to persistent difficulties in agreeing on a fair distribution of costs and benefits. Across all three, the same pattern holds: cross-border cost sharing is acknowledged as necessary but the methodology to achieve the desired cooperation is left uncertain.

The EU Grids Package makes meaningful progress but stops short of resolving the core problem. Article 15 requires Member States only to *consider* cross-border offshore goals, rather than committing to them. Moreover, although Article 17 introduces the benefit-proportional principle, it does not specify which indicators should define net benefits or how the underlying CBA should be conducted, which is a major contributor to the negotiation deadlock under the current framework. In addition, the Commission's newly introduced gap-filling role does not clarify how costs would be allocated in the event of intervention (European Commission, 2025a). Overall, while the Grids Package signals a step in the right direction, it leaves the methodological core of cross-border cost sharing unresolved.

A broader limitation across the reviewed frameworks is their near-exclusive focus on hybrid interconnectors as the reference case for offshore cost-sharing governance, while radial and cross-border radial configurations have received comparatively little attention in both national and EU-level planning (Meeus, 2025). Yet all types of cross-border projects generate similarly asymmetric cost and benefit distributions, and no established framework governs their cost sharing. The policy focus on hybrids, while understandable, leaves a broader class of offshore cooperation arrangements institutionally unaddressed.

The existing cost-sharing framework does not adequately facilitate network investments that serve broader regional or EU-wide interests; such investments continue to be driven predominantly by national needs and nationally captured benefits (Povh, 2025). Abundance of different cooperation options and complexity of detailed design has created barriers to international cooperation- explaining the slow uptake so far (Gephart and Lotz, 2025). There is currently little incentive to build beyond national needs and little incentive/trust to pay for infrastructure in other territories. CBCA is not adequate for providing the necessary grounds for overcoming this due to its limited scope (PCI and CAPEX only), limited applicability (unilateral/bilateral only), and being too complicated while possessing problems of uncertainty (scenarios). Member States need to develop an understanding of the bottom-line net cost sharing across infrastructure and generation assets in order to overcome these challenges.

# 3

# Problem Analysis - Cross-Border Benefit Spillovers in Coupled Electricity Markets

The policy and regulatory review in Chapter 2 establishes that the central challenge of cross-border cost-sharing stems from an asymmetric distribution of costs and benefits across countries where costs are nationally borne while benefits spill across borders through market coupling. Before a formal quantitative model can be constructed to evaluate specific mechanism designs, it is necessary to first establish a conceptual understanding of how and to whom these benefit spillovers actually accrue. This chapter serves that purpose.

The effects of increased offshore wind generation in interconnected electricity markets are examined in this section. Using a simplified two-country coupled market framework, the analysis visualizes how expanding offshore wind capacity in one country affects prices, welfare distribution, and congestion rents in both the domestic and neighboring market. The discussion is further extended to consider the role of reinforcing existing interconnector capacity, representing onshore cross-border transmission upgrades. Together, these graphical scenarios illustrate how market coupling allows part of the economic benefits of offshore wind and transmission investments to spill over to neighboring countries. Understanding these cross-border benefit flows is essential, as they constitute a central source of uncertainty and negotiation challenges in the design of cost-sharing arrangements.

This graphical exercise is heavily inspired by the works of Kristiansen et al. (2018), where they follow a similar approach to visualize changes in social-economic welfare (SEW) and its components as a result of increased interconnector capacity between two countries. Two adjustments are made to their representation. First, the effects of offshore wind capacity expansion are added alongside interconnector reinforcement. This is necessary because offshore wind constitutes a categorically different investment: rather than expanding the bilateral transfer limit, it shifts the supply-side composition at a specific node, introducing a domestic price effect that propagates cross-border only to the extent permitted by existing interconnector capacity. Treating these two investment types in the same framework is essential to understand how their benefits interact and where they diverge. Second, a hypothetical merit-order curve is used rather than empirically calibrated supply and demand functions. This choice is deliberate: anchoring the analysis to a specific market configuration would tie the conclusions to a particular country, season, or demand profile, obscuring the directional insights that hold more generally across stakeholder groups. The hypothetical curve allows the analysis to establish which actors gain and which lose under each scenario without making claims about magnitudes.

## 3.1. Definition of the 3-node system

Purely as an example, Belgium is used as the neighboring region and its wholesale electricity market is the subject to implicit changes as a result of increased offshore wind capacity in the Dutch EEZ and/or reinforcement at the onshore grid. The two countries and additional offshore wind can be represented in a 3-node system as shown in Figure 3.1.

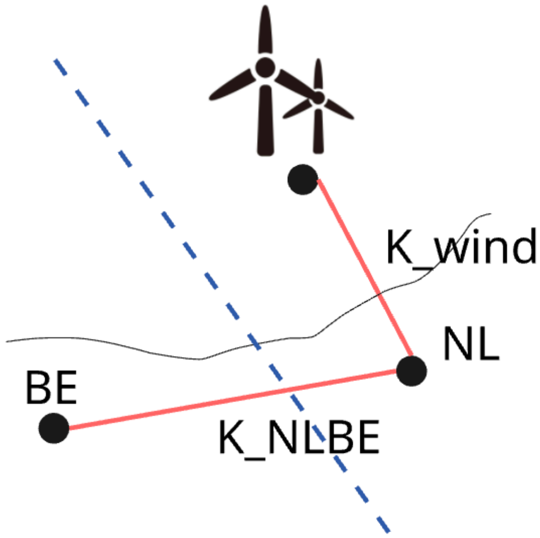



**Figure 3.1:** 3-node system of expanded OW capacity in the Dutch EEZ

In this simplified representation, both countries' supply and demand curves are aggregated to single nodes within a closed system, meaning no other outside connection exists. Here, $K_{NLBE}$ is the total interconnector capacity between The Netherlands and Belgium whereas $K_{wind}$ is the capacity of the radial connection between the offshore wind farm and rest of the onshore Dutch grid.

## 3.2. Load-generation scenarios

In this section, individual cases with varying supply-demand graphs are considered- all of which are completely hypothetical and exaggerated to magnify the impact of expansion effects. Across all cases, the delta represents the change against the status-quo, such as comparing the effects of having more wind energy injected to the Dutch grid vs. not having that additional wind energy in the coupled system.

## Case 1: Offshore wind in NL and NL is exporting

The first case is comparing the effect of increasing offshore wind generation capacity in The Netherlands without any reinforcement on the onshore grid, under the scenario where The Netherlands is exporting to Belgium. The system is visualized in Figure 3.4.

The effects are represented in Figure 3.3. Addition of wind is shown with the supply graph (*with wind*) underneath the status-quo supply graph (*NO wind*). The Netherlands is exporting as they have a lower wholesale price $p_{NL}$ compared to Belgium $p_{BE}$[1]. When additional wind $K_{wind}$ is introduced to the system, prices in the Dutch wholesale market drops to $p_{NLwind}$. As markets are coupled via $K_{NLBE}$, which is of finite capacity and is being utilized to the fullest, the two prices only converge until the interconnector reaches its physical limits. When this happens, markets clear at $d_{NL} + K_{NLBE}$ for The Netherlands

[1]In the graph, only the prices after coupling is presented. Both $p_{NL}$ (and $p_{NLwind}$) and $p_{BE}$ are final prices after the coupled market is cleared, meaning prices prior to coupling are not presented.

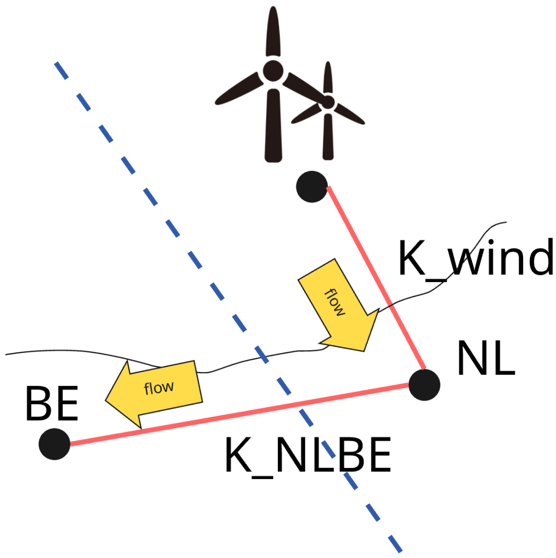



**Figure 3.2:** Case 1: Wind installed at NL and NL is exporting to BE | Interconnector capacity binding | No onshore reinforcements

and $d_{BE} - K_{NLBE}$ for Belgium. Additionally, each country's demand function (WTP) is assumed a constant for clarity.

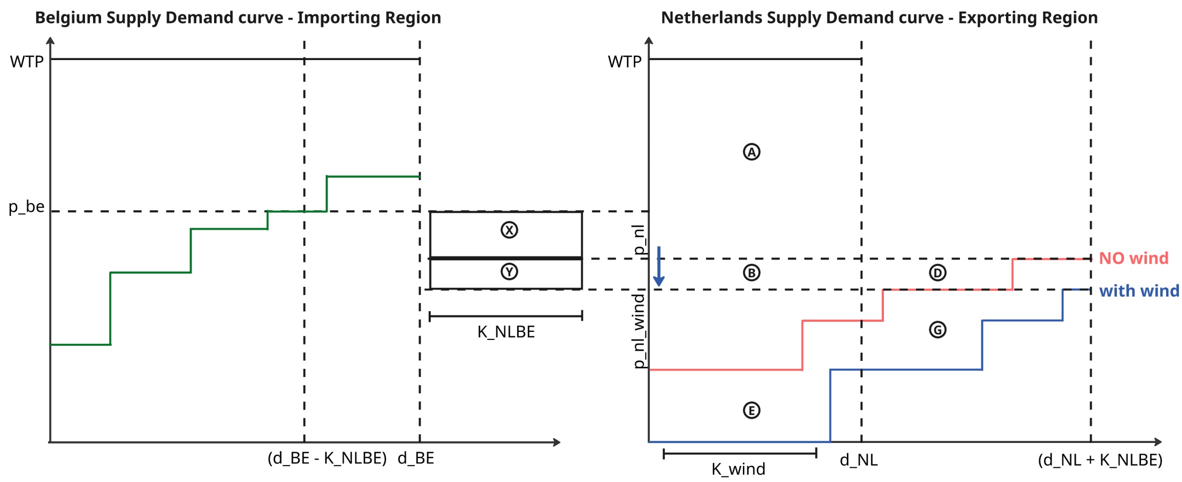



**Figure 3.3:** Wind vs. No wind: Wind installed at NL and NL is exporting to BE | Interconnector capacity binding | No onshore reinforcements

For The Netherlands: Added wind capacity shifts the initial supply curve in NL (shown in red) by $K_{wind}$ to the right (shown in blue), which results in a lower new price $p_{NL_{wind}}$. This leads to a transfer of surplus *B* from producers to the consumers. So, Dutch consumers will always be better off in this situation, strictly from a market-endogenous surplus perspective[2]. For Dutch energy producers, the net effects depend on the areas of $B + D$ and $G + E$. If $B + D$ is greater than $G + E$, the producers will be worse off after more wind is injected to the system and vice versa. However, the generation costs decrease regardless of the shape of the supply-demand functions (areas). Finally the net social economic welfare (SEW)[3] will increase only if $G + E + \Delta CR_{NL} > D$, where $\Delta CR_{NL}$ is the post-wind

[2]Additional costs the Dutch consumers via increased tariffs employed by the TSO may put the consumers at a worse-off position.
[3]Net SEW is defined as the sum of producer and consumer surpluses and congestion rent (Kristiansen et al., 2018).

change in congestion rent allocated to the Dutch TSO- equivalent to the portion of area $Y$ they are entitled to[4]. This can be stated as $f_{CR_{NL}} \cdot Y$.

For Belgium: In retrospect, added wind capacity without onshore reinforcement and a binding interconnector constraint will have differing results in the importing region. Since the interconnector is already fully utilized, no shift in the local prices is observed. Consequently, both the producer and consumers are indifferent to any expansion of wind capacity in The Netherlands. Generation costs are also the same. The only change is a net increase in total SEW of magnitude $f_{CR_{BE}} \cdot Y$ as a result of higher price differential when Belgium's price stays the same against a dropping wholesale price in The Netherlands. This increases the total congestion rents from $X$ to $X + Y$, so the system-wide net change is $Y$.

The effects of increasing wind capacity in The Netherlands with fully utilized interconnector capacity is summarized in Table 3.1.

**Table 3.1:** Case 1 stakeholder surplus impacts summary

| Country | Stakeholder | Δ Effect on Surplus |
|---|---|---|
| NL | Consumers | Increases |
| | Producers | Context-dependent |
| | TSO | Increases |
| | Country net | Context-dependent |
| BE | Consumers | Indifferent |
| | Producers | Indifferent |
| | TSO | Increases |
| | Country net | Increases |

# Case 2: Offshore wind in NL and BE is exporting

Case 2 examines the same wind expansion scenario as Case 1 — no onshore reinforcement, interconnector capacity fully binding — but with the direction of cross-border exchange reversed: The Netherlands is now the importer ($p_{NL} > p_{BE}$). The system is visualized in Figure 3.4.

The effects are represented in Figure 3.5. As in Case 1, $K_{wind}$ shifts the Dutch supply curve rightward, lowering the domestic price to $p_{NL_{wind}}$, which is still assumed to remain above $p_{BE}$.[5] The key departures from Case 1 arise from the import position.

For The Netherlands: Dutch consumers now benefit from two simultaneous effects: the price reduction from additional wind generation and access to cheaper cross-border imports, together recovering areas $B + D + G + K$. Producer and generation cost effects follow the same logic as Case 1. The critical difference is the Dutch TSO: whereas in Case 1 the congestion rent increased with a widening price differential, here the price differential *narrows* as $p_{NL_{wind}}$ falls toward $p_{BE}$. The Dutch TSO therefore always loses congestion revenue, with $\Delta CR_{NL} = f_{CR_{NL}} \cdot X$ representing the decrease. Net SEW increases only if $D + E + G + K > \Delta CR_{NL}$.

For Belgium: As in Case 1, the fully utilized interconnector insulates Belgian consumers and producers from any direct price effect. However, the Belgian TSO effect also reverses: the narrowing price differential reduces congestion revenue from $X + Y$ to $Y$, a loss of

[4]The distribution of congestion rent follows the sharing key allocations agreed upon by participating countries for their interconnectors (Willems et al., 2025).

[5]Were $K_{wind}$ large enough to push $p_{NL_{wind}} < p_{BE}$, The Netherlands would transition into an exporting position — the circumstances of Case 1.

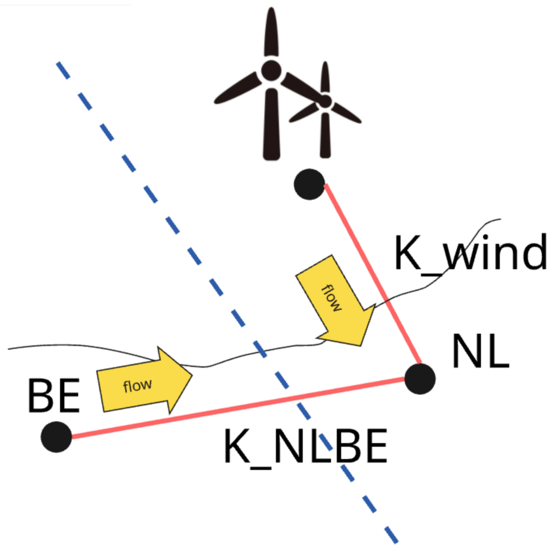



**Figure 3.4:** Case 2: Wind installed at NL and BE is exporting to NL | Interconnector capacity binding | No onshore reinforcements

$f_{CR_{BE}} \cdot X$. It can be stated unambiguously that additional wind capacity in The Netherlands under a binding interconnector constraint will always reduce the Belgian TSO's congestion revenue when Belgium is in the exporting position.

The observations are summarized in Table 3.2.

**Table 3.2:** Case 2 stakeholder surplus impacts summary

| **Country** | **Stakeholder** | **△ Effect on Surplus** |
|---|---|---|
| **NL** | Consumers | Increases |
| | Producers | Context-dependent |
| | TSO | Decreases |
| | Country Net | Context-dependent |
| **BE** | Consumers | Indifferent |
| | Producers | Indifferent |
| | TSO | Decreases |
| | Country Net | Decreases |

## Case 3: Offshore wind in NL with onshore reinforcements

Previous cases did not consider expansion of the onshore interconnection capacity while an important observation was that neither the consumers nor the producers of the neighboring region where there is no expansion in wind generation, realize first-hand benefits. Expanding the existing capacity $K_{NLBE}$ by $k_{wind}$ will allow further benefits to materialize. Under increased interconnection capacity, wholesale prices in Belgium will shift alongside the Dutch prices, so two distinct events will be acting simultaneously at the importing region: price decrease due to expanded interconnection and increased cross-border price differential due to more wind. In this discussion, only the scenario where The Netherlands is exporting to Belgium is considered. The system is visualized in Figure 3.6.

As observed in Figure 3.7, a single supply curve has been provided for both regions. This is because the effects of onshore grid reinforcements are realized through a shift in quantity.

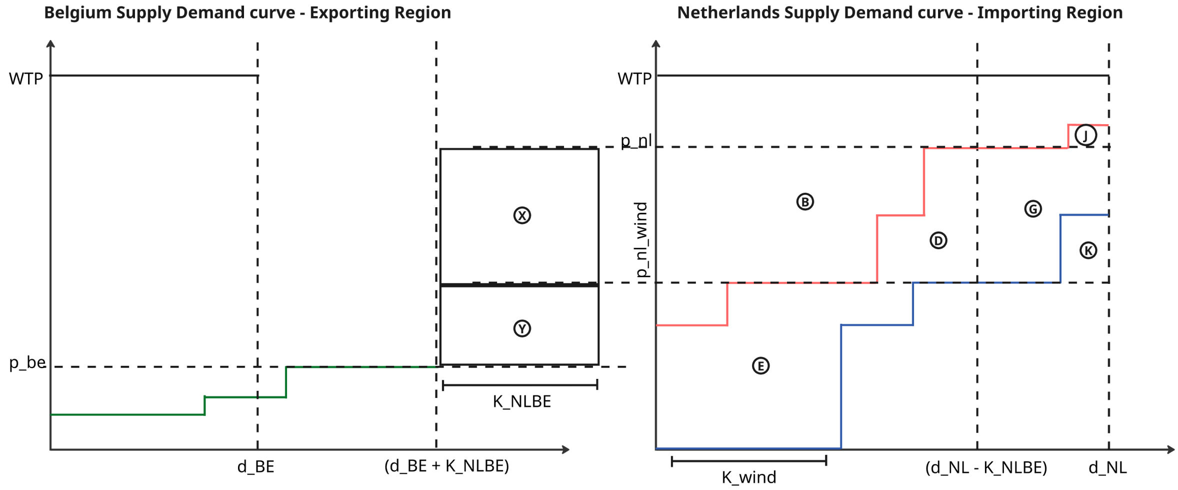



**Figure 3.5:** Wind vs. No wind: Wind installed at NL and BE is exporting to NL | Interconnector capacity binding | No onshore reinforcements

This is an increase in the total load served for the exporting region- i.e. from local demand $d_{NL}$ to the existing market coupling capacity $d_{NL} + K_{NLBE}$ and finally encompassing the reinforced grid $d_{NL} + K_{NLBE} + k_{wind}$. The volume of reinforcement $k_{wind}$ does not have to be equivalent to the installed capacity of $K_{wind}$, but it is assumed this grid expansion is undertaken purely to allow more of the benefits of $K_{wind}$ to materialize.

For The Netherlands: The consumers are worse-off, as expected for an exporting region in a coupled market (Kristiansen et al., 2018). Area $B$ is transferred from the consumers to the producers, who are in favor of increased cross-border transmission capacity as the wholesale price of their region increases, and they increase their total surplus. Since more load is served, higher marginal cost units will be operational under the merit-order, so the total generation cost will increase alongside the producer surplus. Finally, the delta of net SEW depends on the load and generation profiles, and even more so on the change in total congestion rents. The Dutch system gains the areas $F+I$ and the congestion revenue. The congestion rent in the unreinforced setup is $X + Y + L$. The onshore grid reinforcements vertically "shrink" the congestion revenue and horizontally "stretch" it, leading to the new area $Y + Z$. Consequently, the delta in net SEW would increase if area gained $Z$ is larger than the area lost $Y + Z$. Even if total congestion rent decreases, it is still possible to have a net positive change in the net SEW if $F + I$ is larger than this loss.

For Belgium: Same effects apply but in reverse. Importing customers are better off thanks to access to cheaper electricity prices while the producers are stranded away from a portion of their surplus. Generation costs decrease due to fewer high-cost plants being operational. Similar to The Netherlands, the Belgian TSO is similarly affected by the change in total congestion rent. Unless this delta is positive, the net SEW depends on whether the sum of areas $5$ and $6$ is greater than $\Delta CR_{BE}$.

The final effects on the stakeholders' surpluses are summarized in Table 3.3.

Cases 1–3 assume the interconnector is fully binding throughout. When this constraint is non-binding, either because cross-border exchange falls within capacity or because supply-demand profiles are symmetric across countries, both markets clear at a single price and act as one. Under these conditions, wind benefits accrue symmetrically to consumers in both countries, TSOs are indifferent to expansion, the location of wind injection becomes irrelevant, and further onshore reinforcement has no welfare effect. The three cases therefore represent the analytically relevant range for cost-sharing purposes, where benefit distributions are uneven and conditions are not predetermined.

The graphical analysis necessarily abstracts from further complications that compound the

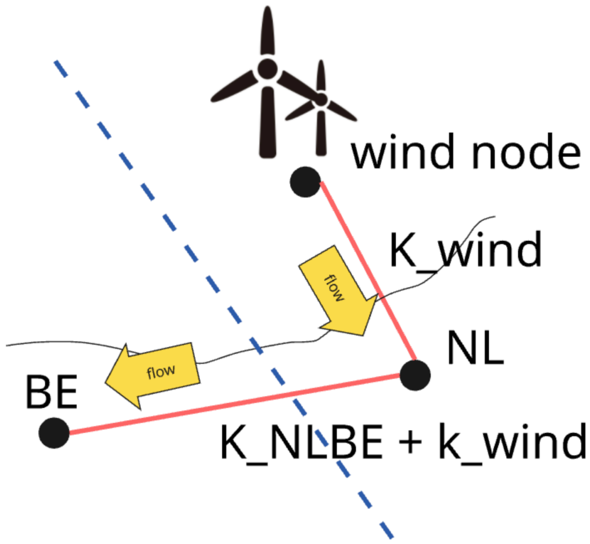



**Figure 3.6:** Wind installed at NL and NL is exporting to BE | Interconnector capacity binding | WITH onshore reinforcements

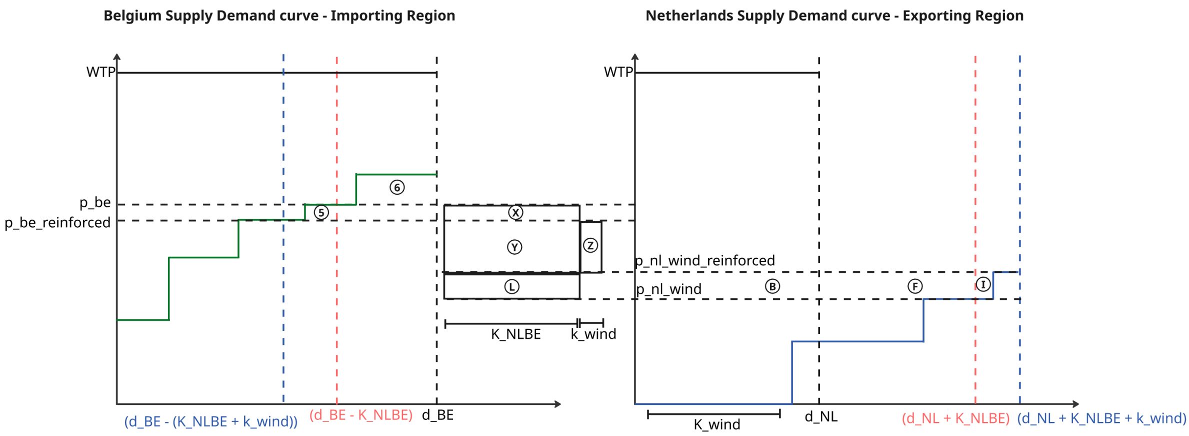



**Figure 3.7:** Reinforcement effect: Wind installed at NL and NL is exporting to BE | Interconnector capacity binding | WITH onshore reinforcements

cost-sharing problem in practice, including the limited incentive for countries anticipating predominantly transit flows to invest in cross-border infrastructure, and the uncertainty introduced by uncoordinated national policies across interconnected systems Roth2026.

## 3.3. Implications for cost-sharing

Firstly, benefits of expansion in offshore wind generation and/or interconnector capacity are distributed unevenly across the stakeholders in each country, which are namely the consumers, producers, and the TSO. As summarized in Table 3.1, Table 3.2, and Table 3.3, the benefits are not always a net positive for these stakeholders and depend on the shapes of the supply-demand curves. Regardless, it is possible to make observations on the position of the stakeholders of both regions. During hours of congestion, consumers and producers of the neighboring region will always be indifferent to wind expansion in the host country unless additional interconnector capacity is built[6]. For host generators, their gains and losses are dictated by the country's import/export status whereas the consumers are better off having the additional wind generation capacity when the interconnector

[6]This holds when it is assumed that benefits are distributed solely through the market-generated surpluses.

**Table 3.3:** Case 3 stakeholder surplus impacts summary

| Country | Stakeholder | △ Effect on Surplus |
|---|---|---|
| **NL** | Consumers | Decreases |
| | Producers | Increases |
| | TSO | Context-dependent |
| | Country Net | Context-dependent |
| **BE** | Consumers | Increases |
| | Producers | Decreases |
| | TSO | Context-dependent |
| | Country Net | Context-dependent |

capacity is binding, at least from a market-endogenous surplus perspective — though tariff adjustments by the TSO may offset part of this gain in practice. Once the onshore transmission lines are reinforced, the full picture calls for a case-by-case approach to determine who benefits how much. This matter is most complex for the TSOs, who have to commit to investments which may occasionally harm them in terms of congestion rents as seen in cases 2 and 3.

A part of benefits from expanding wind generation capacity will directly materialize only if appropriate onshore reinforcements are done. Even if generation and transmission are uniformly considered, there is still the matter of uncertainty. Since it is possible that all scenarios considered in this exercise can formulate under real-life market conditions with no predefined certainty, the distribution of benefits from increasing wind and/or interconnector capacity to each stakeholder is highly sensitive to market conditions.

## 3.4. Validity, limitations, and motivation for Chapter 4

The analysis in the preceding sections is intentionally constrained to the wholesale market clearing layer. Investment costs, interim transactions between actors — such as congestion rent redistribution or compensation transfers for asymmetric benefits — and their effect on consumer tariff adjustments fall outside its reach. These are not peripheral details. They determine whether the benefit flows identified here translate into viable investment incentives in practice, and they are precisely what cost-sharing mechanisms are designed to govern.

Despite these constraints, the results retain meaningful analytical content. The directional conclusions — which stakeholders gain, which lose, and which are indifferent under each configuration — are not contingent on the specific shape of the supply and demand curves used. They hold as structural properties of the bilateral coupled market under the conditions examined, following directly from the mechanics of market coupling itself. What remains unresolved is how to weight these configurations against one another under real market conditions, where the import-export status and congestion state shift continuously across time. Quantifying the expected benefit distribution across operating regimes, and evaluating how different cost-sharing designs alter investment decisions in response, requires a more formal treatment.

This graphical exercise therefore establishes the problem but cannot resolve it. Answering the research questions posed in Chapter 1 requires a framework that can quantify how different cost-sharing mechanism designs influence investment incentives and welfare outcomes under conditions of uneven benefit distribution and market uncertainty. Chapter 4 develops this analytical framework.

# 4
# Methodology

This chapter develops the analytical framework used to evaluate cross-border cost-sharing mechanisms for offshore electricity infrastructure. Building on the conceptual foundation established in the graphical analysis of chapter 3, a formal two-country partial-equilibrium model is constructed to enable a quantitative and comparative assessment of how different mechanism designs influence investment incentives and welfare outcomes.

The chapter first motivates the need for a linearized modeling approach and outlines the key methodological choices underpinning the framework. It then presents the two-country electricity market model, the deterministic operating regimes through which market uncertainty is represented, and the cost structures considered. Finally, the strategic expansion game is introduced, in which countries non-cooperatively propose investment levels and Nash equilibria define the set of mutually agreeable outcomes. The performance of each cost-sharing mechanism is subsequently evaluated against three metrics: efficiency loss, cost-benefit mismatch, and the size of the negotiation space. Finally, the chapter introduces the simulation setup and the sensitivity analyses used throughout the results in Section 4.9.

## 4.1. Motivation and scope of the analytical framework

Building on the structural insights established in Chapter 3, translating those insights into a basis for evaluating cost-sharing mechanism designs requires three properties the graphical approach cannot provide: quantitative precision in welfare decomposition, a consistent functional form that places mechanism designs on equal analytical footing, and tractability sufficient to support the strategic investment game introduced later in this chapter.

These requirements motivate the choice of a linearized model. Linear supply and demand functions yield closed-form expressions for consumer surplus, producer surplus, and congestion rents as explicit functions of capacity parameters. This makes it possible to isolate the marginal welfare contribution of each investment type and to evaluate net SEW changes coherently across mechanism designs. A non-linear or simulation-based approach would either obscure these marginal relationships or make mechanism comparisons contingent on arbitrary functional form choices. Crucially, the analytical purpose here is not to replicate real-world market dynamics with empirical precision, but to compare how different cost-sharing mechanisms perform under consistently specified conditions. For this purpose, a linearized is sufficient. For this, a single-period two-country electricity market model is developed.

The analytical framework was developed for providing the grounds to explore, within a controlled simulation environment, the country-level welfare and surplus effects of different cost-sharing mechanisms based on the established theoretical foundations. Rather than focusing on a specific set of projects, the analysis deliberately abstracts from geographical and project-specific characteristics in order to eliminate location-driven effects. This allows the study to identify more generalizable trends and derive broader insights into how different mechanisms influence the distribution of costs and benefits across countries. The following aspects were used with reference methodologies to establish the approach of the modeling exercise:

- The analysis focuses on cost-sharing tools that have practical relevance or potential application in future cross-border negotiations. Accordingly, the set of considered ex-ante and ex-post mechanisms is limited to those proposed in Willems et al. (2025). This report is widely recognized as a leading reference in the field, particularly in the absence of a unanimously agreed-upon framework for cross-border cost-sharing.
- A conceptual framework for calculating the welfare-based costs and benefits of expanding interconnector capacity across two price zones is constructed based on Willems et al. (2025) and Kristiansen et al. (2018), both of which employ aggregated linear supply and demand curves to represent market effects. This study adopts the same approach to simplify the analysis and enhance its generalizability, as opposed to using a bid-block based formulation that is typically associated with data-intensive, scenario-specific forecasts. Additionally, these existing frameworks are extended by introducing piecewise zero-marginal-cost segments within the supply curves. This modification provides a more comprehensive representation of offshore wind expansion, as it allows the analysis to capture situations where marginal generation costs remain close to zero. In contrast, a fully linear supply curve with a constant slope would not reflect this characteristic of renewable generation. An illustration of this setup is provided in Figure 4.1, with each variable on the figure further explained in Section 4.2.

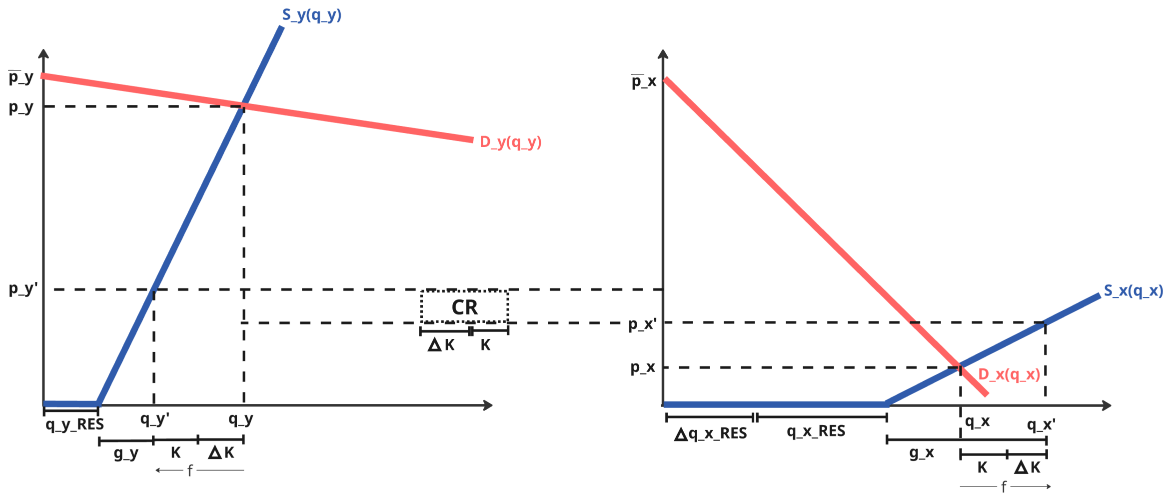



**Figure 4.1:** Two-country coupled electricity market with piecewise supply curves. Country $x$ (right) is the renewable-rich host and country $y$ (left) the supply-constrained importer. Key variables include interconnector flow $f$, existing capacity $K$, expansion $\Delta K$, offshore wind expansion $\Delta q_{x,\text{RES}}$, and congestion rent CR.

- The analysis is based solely on the supply and demand curves of two hypothetical countries, without explicitly modeling the physical electricity network. As such, electrical flow characteristics such as power losses or loop flows are not considered. This simplification is necessary to abstract from the project- or sea-basin-specific approaches outlined in Willems et al. (2025). While such detailed representations are essential for real-world cost-benefit assessments, incorporating them here would tie the results to a specific network configuration, undermining the broader applicability across EU settings that this analysis targets.

  More fundamentally, the primary objective of this model is comparative: to evaluate how different cost-sharing mechanisms perform relative to one another under consistently specified conditions, not to replicate absolute welfare outcomes with empirical precision. Network complexities such as loop flows, power losses, or multi-zone flow factor interactions would, in a closed simulation environment, affect all mechanisms under evaluation symmetrically. They would shift absolute welfare magnitudes but would not systematically advantage or disadvantage any particular mechanism relative to the others. The comparative conclusions — which mechanisms better align investment incentives, reduce efficiency losses, or narrow cost-benefit mismatches — are therefore robust to this class of simplification, provided the mechanisms are held to the same network conditions throughout. Where network complexity does become analytically relevant is in translating these comparative insights into project-specific cost-benefit assessments, which lies beyond the scope of this analysis.

- Under different operating or market conditions, countries may find themselves in positions where additional wind capacity or interconnector expansion is either beneficial or disadvantageous. This uncertainty is incorporated by adopting an approach similar to Loureiro et al. (2019), who explicitly identify distinct operating conditions and assign weights to them to reflect their relative frequency. This study follows the same logic and extends it further by computing expected values that aggregate these conditional outcomes across regimes. These expected values are then used by the actors in the Nash game when making their strategic investment decisions. It should be noted that the regime weights are treated as perfectly known parameters rather than probabilistic estimates: the model assumes full knowledge of how frequently each operating condition materializes, abstracting from the deeper uncertainty that would arise if these frequencies were themselves unknown or contested.
- A key aspect in evaluating the performance of the cost-sharing mechanisms is how they influence the scope for negotiation between countries. In this study, the negotiation space is defined as the set of Nash equilibrium points identified along the expansion grid resulting from the non-cooperative Nash game. This perspective has not been explicitly explored in previous studies and therefore provides a novel angle within the broader discussion on cross-border cost sharing.
- The model is formulated as a single-period optimization problem, in contrast to Kristiansen et al. (2018), who employ a multi-period framework over a long time horizon ($\approx$ 30 years) and account for intertemporal effects through annuity factors. In the present study, a single-period setup is sufficient because the analysis focuses on a stylized and hypothetical setting in which parameters can be interpreted in annualized form. Moreover, the framework is linear, deterministic, and aggregated, and investment decisions are treated as exogenous to the market-clearing problem. Under these assumptions, introducing multiple periods without additional intertemporal state or decision variables would simply replicate the same equilibrium in each period and therefore would not affect the resulting welfare comparisons.

Together, these design choices form a coherent simulation framework that translates the analytical structure into a computational procedure in Python. Starting from a configuration file of economic and institutional parameters, the model iterates over a grid of expansion scenarios, resolves each deterministic operating regime, aggregates welfare outcomes across regimes, and feeds the resulting welfare surfaces into a strategic Nash game. An overview of this process is provided in Figure 4.2.

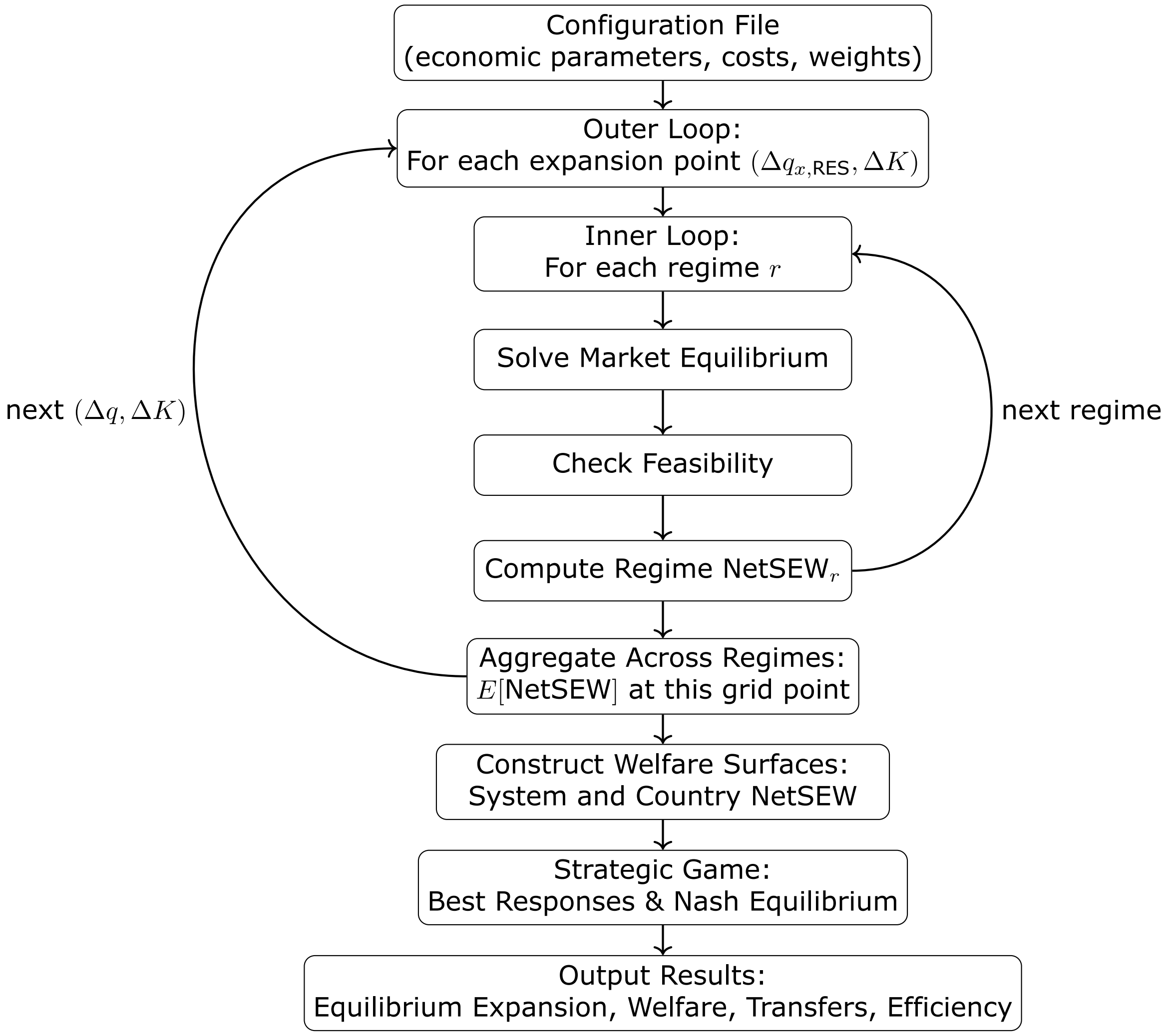



**Figure 4.2:** Simulation workflow with nested loops over expansion scenarios and operating regimes.

# 4.2. Two-country electricity market model

This section presents the analytical formulation of the same coupled two-country electricity market introduced in the graphical analysis of chapter 3. The simplified two-zone system with offshore wind injection and a cross-border interconnector is now expressed as a formal market-clearing problem. The framework represents two hypothetical countries $x$ and $y$ as two nodes connected by an interconnector with finite capacity and defines the market outcome within a single-period setting.

Let $n \in \{x, y\}$ denote the node/region.

## Parameters

For each node $n$:

- $\bar{\lambda}_n > 0$ : choke price
- $a_{Dn} > 0$ : (inverse) demand slope

Inverse demand (willingness-to-pay / price as a function of consumption):

$$\lambda_n(q_n) = \bar{\lambda}_n - a_{Dn} q_n \qquad \text{(inverse demand)}. \tag{4.1}$$

For each node $n$ (dispatchable generation cost):

- $a_{Sn} > 0$ : slope parameter of dispatchable marginal cost

Marginal cost and total cost for dispatchable generation $g_n$:

$$MC_n(g_n) = a_{Sn}\, g_n, \tag{4.2}$$
$$C_n(g_n) = \int_0^{g_n} a_{Sn} u\, du = \tfrac{1}{2} a_{Sn} g_n^2. \tag{4.3}$$

Exogenous RES injections:

$$q_{x,\text{RES}} \geq 0, \qquad q_{y,\text{RES}} \geq 0. \tag{4.4}$$

Interconnector:

$$K \geq 0 \qquad \text{(symmetric flow limit).} \tag{4.5}$$

## Decision variables

- $q_x \geq 0,\ q_y \geq 0$ : cleared consumption at nodes $x, y$
- $f \in \mathbb{R}$ : interconnector flow, positive from $x \to y$

Define dispatchable generation (net of RES and trade) at each node:

$$g_x = q_x - q_{x,\text{RES}} + f, \tag{4.6}$$
$$g_y = q_y - q_{y,\text{RES}} - f. \tag{4.7}$$

## Objective (net social welfare)

Consumer surplus (integral under inverse demand) minus generation costs:

$$\max_{q_x, q_y, f} \sum_{n \in \{x,y\}} \left( \bar{\lambda}_n q_n - \tfrac{1}{2} a_{Dn} q_n^2 \right) - \tfrac{1}{2} a_{Sx} \left(q_x - q_{x,\text{RES}} + f\right)^2 - \tfrac{1}{2} a_{Sy} \left(q_y - q_{y,\text{RES}} - f\right)^2. \tag{4.8}$$

## Constraints

Interconnector capacity:

$$-K \leq f \leq K. \tag{4.9}$$

Non-negativity of dispatchable generation:

$$g_x = q_x - q_{x,\text{RES}} + f \geq 0, \tag{4.10}$$
$$g_y = q_y - q_{y,\text{RES}} - f \geq 0. \tag{4.11}$$

(Also $q_x \geq 0,\ q_y \geq 0$; these are not included in the written Lagrangian.)

## Dual variables

Assign dual variables:

- $\mu^+ \geq 0$ for $f - K \leq 0$ (upper flow limit)
- $\mu^- \geq 0$ for $-f - K \leq 0$ (lower flow limit)
- $\nu_x \geq 0$ for $q_{x,\text{RES}} - q_x - f \leq 0$ (equivalently $q_x + f - q_{x,\text{RES}} \geq 0$)
- $\nu_y \geq 0$ for $q_{y,\text{RES}} - q_y + f \leq 0$ (equivalently $q_y - f - q_{y,\text{RES}} \geq 0$)

## Lagrangian

$$\begin{aligned}\mathcal{L} = &\sum_{n \in \{x,y\}} \left( \bar{\lambda}_n q_n - \tfrac{1}{2} a_{Dn} q_n^2 \right) - \tfrac{1}{2} a_{Sx} (q_x - q_{x,\text{RES}} + f)^2 - \tfrac{1}{2} a_{Sy} (q_y - q_{y,\text{RES}} - f)^2 \\ &+ \mu^+ (K - f) + \mu^- (K + f) + \nu_x (q_x + f - q_{x,\text{RES}}) + \nu_y (q_y - f - q_{y,\text{RES}})\end{aligned} \tag{4.12}$$

## KKT conditions
**Optimality**

$$\frac{\partial \mathcal{L}}{\partial q_x}: \quad (\bar{\lambda}_x - a_{Dx} q_x) - a_{Sx} g_x + \nu_x = 0, \tag{4.13}$$
$$\frac{\partial \mathcal{L}}{\partial q_y}: \quad (\bar{\lambda}_y - a_{Dy} q_y) - a_{Sy} g_y + \nu_y = 0, \tag{4.14}$$
$$\frac{\partial \mathcal{L}}{\partial f}: \quad -a_{Sx} g_x + a_{Sy} g_y - \mu^+ + \mu^- + \nu_x - \nu_y = 0, \tag{4.15}$$

with $g_x = q_x - q_{x,\text{RES}} + f$ and $g_y = q_y - q_{y,\text{RES}} - f$.

**Primal feasibility**

$$f - K \leq 0, \tag{4.16}$$
$$-f - K \leq 0, \tag{4.17}$$
$$q_{x,\text{RES}} - q_x - f \leq 0 \quad (\Leftrightarrow \; q_x + f - q_{x,\text{RES}} \geq 0), \tag{4.18}$$
$$q_{y,\text{RES}} - q_y + f \leq 0 \quad (\Leftrightarrow \; q_y - f - q_{y,\text{RES}} \geq 0), \tag{4.19}$$
$$q_x \geq 0, \qquad q_y \geq 0 \tag{4.20}$$

**Complementary slackness**

$$\mu^+(K - f) = 0, \tag{4.21}$$
$$\mu^-(K + f) = 0, \tag{4.22}$$
$$\nu_x(q_x + f - q_{x,\text{RES}}) = 0, \tag{4.23}$$
$$\nu_y(q_y - f - q_{y,\text{RES}}) = 0 \tag{4.24}$$

**Dual feasibility**

$$\mu^+ \geq 0, \qquad \mu^- \geq 0, \qquad \nu_x \geq 0, \qquad \nu_y \geq 0 \tag{4.25}$$

# 4.3. Deterministic Regimes

The single period market clearance optimization problem holds for all distinct operational conditions, meaning one would have to find the optimal solution to the same linear optimization problem regardless of the node-specific export-import or generation conditions or parameter characteristics. Depending on which constraint is binding (or not binding), the optimal solution will change. This merits a case-by-case analysis of the possible conditionalities.

Two constraints are bounding the solution space: interconnector congestion status, forming the primary regime of the solution space, and the dispatchable generation status at each node, the second regime. The generation status dictates the piecewise transition from the $q_{nRES}$ portion of the supply curve with a constant price at $\lambda = 0$ to the linear $MC(g_n)$ segment.

## Primary Regimes - line congestion

There are 3 mutually exclusive interconnector regimes defined by:

- L0 $\rightarrow$ Uncongested: $-K < f < K \Rightarrow \mu^+ = \mu^- = 0$
- L+ $\rightarrow$ Congested at upper bound: $f = K \Rightarrow \mu^+ \geq 0$, $\mu^- = 0$
- L- $\rightarrow$ Congested at lower bound: $f = -K \Rightarrow \mu^- \geq 0$, $\mu^+ = 0$

It is safe to ignore the case where both $\mu^+ \geq 0$ and $\mu^- \geq 0$ as this can only happen when $f = K = -K = 0$. Since interconnector capacity is assumed to already exist, this case can be ignored.

## Secondary Regimes - dispatchable generation

Independently, each node can either have non-zero $g_n > 0$ or no dispatchable generation $g_n = 0$, in which case the constraint would be binding. 4 generation-subregimes are defined:

- GOO: $g_x > 0$, $g_y > 0$, both slack
- G1O: $g_x = 0$, $g_y > 0$, $x$ binds, $y$ slack
- GO1: $g_x > 0$, $g_y = 0$, $x$ slack, $y$ binds
- G11: $g_x = 0$, $g_y = 0$, both bind

where $g_x = q_x - q_{x,\text{RES}} + f$ and $g_y = q_y - q_{y,\text{RES}} - f$.

In total, there are $8$ relevant combinations of primary and secondary regimes. Each one of these combinations represent the various operational conditions the coupled market can be expected to be physically operating under, at any given moment. The full list of operation regimes are provided in Table 4.1.

**Table 4.1:** Deterministic operating regimes of the coupled-market model

| ID | Code | Active constraints / multipliers | Physical operating condition |
|---|---|---|---|
| 1 | L0G00x | $0 < f < K$, $g_x > 0$, $g_y > 0$; $\mu^+ = \mu^- = 0$, $\nu_x = \nu_y = 0$ | Uncongested ($x \to y$), dispatchable generation in both regions |
| 2 | L0G00y | $-K < f < 0$, $g_x > 0$, $g_y > 0$; $\mu^+ = \mu^- = 0$, $\nu_x = \nu_y = 0$ | Uncongested ($y \to x$), dispatchable generation in both regions |
| 3 | L0G10 | $0 < f < K$, $g_x = 0$, $g_y > 0$; $\mu^+ = \mu^- = 0$, $\nu_x \geq 0$, $\nu_y = 0$ | Uncongested ($x \to y$), wind displaces dispatchable gen. in $x$ |
| 4 | L0G01 | $-K < f < 0$, $g_x > 0$, $g_y = 0$; $\mu^+ = \mu^- = 0$, $\nu_x = 0$, $\nu_y \geq 0$ | Uncongested ($y \to x$), wind displaces dispatchable gen. in $y$ |
| 5 | L+G00 | $f = K$, $g_x > 0$, $g_y > 0$; $\mu^+ \geq 0$, $\mu^- = 0$, $\nu_x = \nu_y = 0$ | Export ($x \to y$) congestion, dispatchable gen. everywhere |
| 6 | L+G10 | $f = K$, $g_x = 0$, $g_y > 0$; $\mu^+ \geq 0$, $\mu^- = 0$, $\nu_x \geq 0$, $\nu_y = 0$ | Export ($x \to y$) congestion with wind-dominated $x$ |
| 7 | L-G00 | $f = -K$, $g_x > 0$, $g_y > 0$; $\mu^- \geq 0$, $\mu^+ = 0$, $\nu_x = \nu_y = 0$ | Import ($y \to x$) congestion, dispatchable marginal everywhere |
| 8 | L-G01 | $f = -K$, $g_x > 0$, $g_y = 0$; $\mu^- \geq 0$, $\mu^+ = 0$, $\nu_x = 0$, $\nu_y \geq 0$ | Import ($y \to x$) congestion with wind-dominated $y$ |

For any analysis, it needs to be acknowledged that the solution (optimal values) of the market clearance problem may reside within any of the 8 regimes, with all being possible operational conditions during a year or the lifespan of the infrastructure. It is, however, possible to capture this case-dependent nature of the problem with a streamlined, singular expression by reformulating the objective function, Equation 4.8, that incorporates the fixed parameters of each case in Table 4.1 through a weighted sum in 8 ”snapshots”. For each case, a weight $\omega_r$ is defined:

$$\sum_{r=1}^{8} \omega_r = 1, \qquad \omega_r \geq 0 \ \forall r \in \{1, \ldots, 8\}$$

Weights $w_r$ would indicate the likelihood of occurrence of $r$th operation condition in practice. They are parameters completely exogenous to the optimization problem and would likely be obtained through country-specific historical data analysis or future forecasts. The more likely an operational condition is to occur in practice, the more dominant the term of the general solution accounting for the corresponding regime will be.

Realizing that each regime is a possible operational condition with various likelihood of occurrence, a new objective function (SEW-maximizing) accounting for all possible regimes is formulated in Equation 4.26. This regime-weighted formulation is best interpreted as a scenario-weighted collection of deterministic market clearances (a collection of possible operating points), rather than a single market outcome with uncertainty resolved endogenously.

$$\begin{aligned}\max_{\{q_{x,r},\, q_{y,r},\, f_r\}_{r=1}^{8}} \quad \sum_{r=1}^{8} \omega_r \Bigg[ & \sum_{n\in\{x,y\}} \left(\bar{\lambda}_{n,r}\, q_{n,r} - \tfrac{1}{2} a_{Dn,r}\, q_{n,r}^2\right) \\ & - \tfrac{1}{2} a_{Sx,r} \left(q_{x,r} - q_{x,\text{RES}} + f_r\right)^2 \\ & - \tfrac{1}{2} a_{Sy,r} \left(q_{y,r} - q_{y,\text{RES}} - f_r\right)^2 \Bigg]\end{aligned} \tag{4.26}$$

The model is evaluated across a range of capacity expansion scenarios, defined by two dimensions: $\Delta K$, the incremental addition to interconnector capacity, and $\Delta q_{x,\text{RES}}$, the incremental addition to offshore wind generation capacity in country $x$. These are not variables within the optimization problem itself. Rather, they define discrete evaluation points over which the optimization is solved independently. At each point on the expansion space, a specific combination of $\Delta K$ and $\Delta q_{x,\text{RES}}$ is fixed externally, the market-clearing problem is solved under those conditions, and the resulting welfare outcomes are recorded. This is then repeated for all possible combinations of $\Delta K$ and $\Delta q_{x,\text{RES}}$.

**Solving the regime-weighted optimization problem**
The regime-weighted formulation *appears* as one large optimization with $24$ primal decision variables $\{q_{x,r}, q_{y,r}, f_r\}_{r=1}^{8}$ and $24$ stationarity conditions (three per regime). However, since:

1. the objective is a separable sum over regimes
2. all constraints and multipliers are regime-indexed (i.e., there are no cross-regime linking constraints)

the full KKT system decomposes into eight independent problems. In practice, each regime $r$ is solved separately by taking the three optimality equations in $(q_{x,r}, q_{y,r}, f_r)$ and enforcing the regime's binding pattern from Table 4.1 (e.g., $f_r = \pm K$ if congested, $g_{x,r} = 0$ or $g_{y,r} = 0$ if dispatchable generation is displaced). In interior cases, the relevant multipliers are zero and the regime reduces to a clean $3$-equations/$3$-unknowns system; in boundary cases, the regime equalities (such as $f_r = \pm K$ or $g_{x,r} = 0$) effectively replace one unknown and imply which multipliers can be nonzero. After computing the regime-wise optimal quantities, the weights $\omega_r$ are only used to aggregate outputs, rather than materially affecting the regime-wise primal solutions themselves.

Solutions to each regime have been provided in Appendix A.

# 4.4. Costs

In a comprehensive study considering long-run costs of transmission lines under complex loop-flow calculations, Rosellón, Vogelsang, and Weigt (2010) tests four forms of line extension functions. The tested cost functions consist of a linear (constant marginal cost), logarithmic (economies of scale), quadratic (diseconomies of scale), and the lumpy function that represents the integer nature of line extensions. They conclude linear cost functions are appropriate for most modeling exercises. Consistent with the simplified linear structure of the framework, the linear cost function of Rosellón et al. (2010) is adopted in the present analytical formulation, as shown in Equation 4.27.

$$\text{C}_{\text{trans}} = c_{\text{trans}} \Delta K \tag{4.27}$$

where $\text{C}_{\text{trans}}$ is the cost of expansion in interconnector capacity between countries $x$ and $y$, scaling with a constant marginal multiplier $c_{\text{trans}}$ in [€/MW]. Similarly the investment cost of the radial connection from the offshore wind farm to shore, $\mathsf{C}_{\text{radial}}$- which is historically covered by the host nation, is represented by Equation 4.28.

$$\mathsf{C}_{\text{radial}} = c_{\text{radial}} \Delta q_{x,\text{RES}} \tag{4.28}$$

where the cost is scaled with $c_{\text{radial}}$ per unit of injected/installed offshore wind in [€/MW]. Capital cost of the offshore wind farm is assumed to be undertaken by the developer, and thus are not considered as a negative component to the system welfare.

It is important to note that only CAPEX are considered. With all system level costs defined, the costs can be partitioned across the countries based on the chosen allocation method with sharing key $\alpha_n$ as shown in Equation 4.29.

$$\mathsf{C}_{\text{total}} = \mathsf{C}_x + \mathsf{C}_y, \tag{4.29a}$$
$$\mathsf{C}_x = \alpha_x \big(\mathsf{C}_{\text{trans}} + \mathsf{C}_{\text{radial}}\big), \tag{4.29b}$$
$$\mathsf{C}_y = \alpha_y \big(\mathsf{C}_{\text{trans}} + \mathsf{C}_{\text{radial}}\big), \tag{4.29c}$$
$$\alpha_x + \alpha_y = 1 \tag{4.29d}$$

# 4.5. Mechanism implementation in the model

This section describes how each cost-sharing mechanism is implemented within the analytical framework. Four mechanisms are considered: two ex-ante allocation rules that determine each country's cost share prior to market realization, and two ex-post instruments that redistribute surpluses between countries after the market has cleared. All mechanisms are expressed in terms of the model's market-clearing variables and regime-specific outcomes, and are evaluated across the full set of eight operating regimes using the probabilistic weights $\omega_r$.

## 4.5.1. Ex-ante - 50–50 split

Under the 50–50 split, investment costs are divided equally between the two countries, irrespective of the benefits each realizes, such that each country bears half of the total cost of each asset it participates in. The sharing keys are set to 0.5 for both.

$$\alpha_x = 0.5 \qquad \text{and} \qquad \alpha_y = 0.5$$

## 4.5.2. Ex-ante - benefit-proportional (BP)

Defining the allocation of sharing keys that are proportional to benefits requires the calculation of benefits, defined as the difference between the post-market clearance total surplus (PS+CS+CR) with expanded capacity and total surplus in the counterfactual scenario without any expansion. For each country, the benefit, $\mathsf{B}_{\mathsf{n}}$ can be represented as:

$$\mathsf{SEW}_n = \sum_{r=1}^{8} \omega_r \left[ \big(\bar{\lambda}_{n,r}\, q_{n,r} - \tfrac{1}{2} a_{Dn,r}\, q_{n,r}^2\big) - \tfrac{1}{2} a_{Sn,r}\, g_{n,r}^2 + \mathsf{CR}_{n,r} \right], \qquad \forall\, r \in \{1,\ldots,8\},$$
$$\mathsf{B}_n = \mathsf{SEW}_n\big(\Delta K,\, \Delta q_{x,\text{RES}}\big) - \mathsf{SEW}_n(0,\, 0)\,,$$

Congestion rent accounted for in the country-specific benefits for the calculation of the BP-based sharing key are split via the 50-50 split. The proportional-to-benefit share key is then defined as:

$$\alpha_x = \frac{\mathsf{B_x}}{\mathsf{B_x} + \mathsf{B_y}} \qquad \text{and} \qquad \alpha_y = \frac{\mathsf{B_y}}{\mathsf{B_x} + \mathsf{B_y}}$$

### 4.5.3. Ex-post - CfD for transmission

In the present analysis, the formulation of Kristiansen et al. (2018) is adapted to a simplified bilateral setting that preserves the core intuition of the mechanism while aligning with the model structure. The multi-country framework is reduced to two regions, such that the balancing condition in Equation 2.2 holds implicitly through bilateral transfers between country $x$ and country $y$, and transmission losses are neglected in line with the stylized setup.

The transmission CfD is implemented in the bilateral setting of this study through the following definitions. The regime-contingent side payments ($\widetilde{\text{CfD}}_n^{\text{trans}}$, $n \in \{x, y\}$) are computed for each country based on the local price and the direction of cross-border flow in each regime. Exogenous to the optimization problem, a CfD strike price $\lambda_{\text{CfD}}^{\text{trans}}$ is specified.

For each regime $r$, the settlement is determined by the strike–price spread $(\lambda_{\text{CfD}}^{\text{trans}} - \lambda_{n,r})$ applied to the share of cross-border flow attributed to the expanded interconnector. The sign of the flow $f_r$ determines the direction of settlement for each country. As a simplifying assumption, only the share of flows attributable to the expanded interconnector is considered through the scaling $\frac{\Delta K}{K'}$, representing the share of additional interconnector capacity over the cumulative installed capacity. This proportional attribution follows directly from the aggregated single-flow structure of the model: since flows are not resolved at the line level, there is no basis for isolating the flow increment above existing capacity. Under the assumption that capacity expansion increases total flow proportionally, $\frac{\Delta K}{K'}$ is the natural scaling factor consistent with Kristiansen et al. (2018), who ground transmission CfD settlements in the flows specific to the contracted line.

The regime-contingent side payments are aggregated using the regime weights $\omega_r$ to obtain expected transfers:

$$\widetilde{\text{CfD}}_x^{\text{trans}} = \sum_{r=1}^{8} \omega_r \left(\lambda_{\text{CfD}}^{\text{trans}} - \lambda_{x,r}\right) \left(-\frac{\Delta K}{K'} f_r\right), \tag{4.31}$$

$$\widetilde{\text{CfD}}_y^{\text{trans}} = \sum_{r=1}^{8} \omega_r \left(\lambda_{\text{CfD}}^{\text{trans}} - \lambda_{y,r}\right) \left(\frac{\Delta K}{K'} f_r\right). \tag{4.32}$$

Because each country's gross position is computed against its own local price, the two positions are generally not guaranteed to be equal in magnitude. To obtain the final net transfers, the mechanism is therefore implemented as a two-sided, budget-balanced clearing arrangement, where each country's position is defined relative to the counterparty. This netting step ensures that the final transfer reflects the combined effect of both price deviations, while preserving financial neutrality at the system level:

$$\text{CfD}_x^{\text{trans}} = \widetilde{\text{CfD}}_x^{\text{trans}} - \widetilde{\text{CfD}}_y^{\text{trans}}, \tag{4.33}$$

$$\text{CfD}_y^{\text{trans}} = \widetilde{\text{CfD}}_y^{\text{trans}} - \widetilde{\text{CfD}}_x^{\text{trans}}, \tag{4.34}$$

such that

$$\text{CfD}_x^{\text{trans}} + \text{CfD}_y^{\text{trans}} = 0. \tag{4.35}$$

### 4.5.4. Ex-post - CfD for generation

The mechanism is based on the deviation between the strike price and the realized market price of electricity. When the strike price exceeds the spot price (top panel), the OWF operator is compensated, with both countries contributing according to the cost-sharing rule, leading to a reduction in their respective surpluses. Conversely, when the spot price exceeds the strike price (bottom panel), the OWF operator pays back the difference, and these revenues are distributed to the government, increasing country-level surplus. In the model, this implies that CfD-related payments are internalized at the country level, with transfers effectively redistributing surplus between countries via the OWF, depending on market outcomes and the agreed sharing mechanism. From a regional planner's perspective, the neighboring country's government would be expected to participate in the compensation of the offshore wind asset in the host region. The expression for such a setup is provided in Equation 4.36.

$$\mathsf{CfD}_{\mathsf{gen}} = \mathsf{CfD}_x^{\mathsf{gen}} + \mathsf{CfD}_y^{\mathsf{gen}}, \tag{4.36a}$$

$$\mathsf{CfD}_x^{\mathsf{gen}} = \sum_{r=1}^{8} \omega_r \, \alpha_x \big(\lambda_{\mathsf{CfD}}^{\mathsf{gen}} - \lambda_{x,r}\big) \, \Delta q_{x,\mathsf{RES}}, \tag{4.36b}$$

$$\mathsf{CfD}_y^{\mathsf{gen}} = \sum_{r=1}^{8} \omega_r \, \alpha_y \big(\lambda_{\mathsf{CfD}}^{\mathsf{gen}} - \lambda_{x,r}\big) \, \Delta q_{x,\mathsf{RES}}, \tag{4.36c}$$

with

$$\alpha_x + \alpha_y = 1, \tag{4.36d}$$

where $\mathsf{CfD}_n^{\mathsf{gen}}$, $n \in \{x, y\}$, is the cost of CfD-support paid by the TSO(s) to the offshore wind farm developer as a function of injected wind $\Delta q_{x,\mathsf{RES}}$. The parameter $\lambda_{\mathsf{CfD}}^{\mathsf{gen}}$ is the strike price agreed upon between the OWF project developer and the respective government(s). This arrangement assumes that the CfD would cover only the newly installed wind capacity. The regime weights $\omega_r$ aggregate regime-contingent settlements into an expected transfer level, while the regime-specific prices $\lambda_{x,r}$ reflect the market outcome under operating condition $r$.

It is important to note that this formulation is valid for the underlying assumption where wind expansion occurs at country $x$ and that the OWF participates in the same national wholesale market (i.e., no offshore bidding zone). If installations at $y$ (introduction of a new variable $\Delta q_{y,\mathsf{RES}}$) or a different price zone are to be considered, the price term $\lambda_{x,r}$ should be changed accordingly. Finally, this mechanism acts as a two-sided CfD. When parametrized, the model may clear the market at a higher regime-specific price than the CfD strike price ($\lambda_{x,r} > \lambda_{\mathsf{CfD}}^{\mathsf{gen}}$). In this case, the OWF operator pays back any gains above the strike price, leading to negative costs (benefits) for both countries.

## Treating the CfD for generation as an external cost component

The generation CfD is treated as a cost component in the net SEW calculation rather than as a transfer that cancels in aggregation. This requires brief justification.

Unlike the transmission CfD, which is structured as a bilateral, budget-balanced clearing arrangement between the two countries such that $\mathsf{CfD}_x^{\mathsf{trans}} + \mathsf{CfD}_y^{\mathsf{trans}} = 0$ and therefore cancels in aggregation, the $\mathsf{CfD}^{\mathsf{gen}}$ payment flows from the two governments to the OWF developer, which is an agent that lies outside the model's welfare accounting. Since the OWF developer is not modeled as a welfare-bearing agent, the payment does not re-enter the surplus calculation on the receiving side. From the perspective of the two countries, it is a fiscal outflow with no corresponding inflow within the modeled system. This treatment is further consistent with CBA practice: in an OBZ configuration[1], the producer surplus of the OWF accrues at the offshore price node and is not attributed to the host country, since the actual welfare gains materialize as consumer surplus in the onshore bidding zones to which the energy is delivered (ENTSO-E – European Network of Transmission System Operators for Electricity, 2023). Including the CfD payment on the receiving side of the welfare ledger would therefore misattribute benefits to the host country that in practice

[1] PS treatment specific to the present radial configuration in a cross-border setting is not present in any existing framework, so the OBZ-setting is taken as a complementary reference.

accrue elsewhere. Aggregating across both countries thus yields a net reduction in total system welfare proportional to the total expected CfD outlay. This is not because CfDs are inherently welfare-reducing instruments, but because the welfare gains they enable (through incentivizing investment) accrue to agents and timescales outside the scope of this single-period model.

### 4.5.5. Ex-post - congestion rent

ACER (2021) distinguishes between commercial and physical flows, specifying that commercial flows should be used for calculating sharing keys. In the two-zone market model defined earlier, this distinction does not arise: since all flows through the interconnector originate from a simultaneously cleared coupled market, the single flow variable $f$ captures both functions, meaning that physical flows directly correspond to the scheduled commercial exchange.

In order to define an expression for congestion rent (CR), the price differential across each zone is required. For this, regime-specific prices $\lambda_{x,r}$ and $\lambda_{y,r}$ $\forall r \in \{1,\ldots,8\}$ implicitly defined via the inverse demand function are used as shown in Equation 4.37:

$$\lambda_{x,r} = \bar{\lambda}_{x,r} - a_{Dx,r}\, q_{x,r}, \qquad \forall r \in \{1,\ldots,8\}, \tag{4.37a}$$

$$\lambda_{y,r} = \bar{\lambda}_{y,r} - a_{Dy,r}\, q_{y,r}, \qquad \forall r \in \{1,\ldots,8\}. \tag{4.37b}$$

Given the inverse demand function, CR can be defined using a simplified version of the optimization problem's objective function from the CID methodology[2], accounting for only a single flow variable and only 2 price zones as shown in Equation 4.38:

$$\text{CR}_{\text{total}} = \sum_{r=1}^{8} \omega_r \Big( \text{CR}_{x,r} + \text{CR}_{y,r} \Big) \tag{4.38a}$$

where, for each $r \in \{1,\ldots,8\}$,

$$\text{CR}_{x,r} = \alpha_x \left| f_r(\lambda_{y,r} - \lambda_{x,r}) \right|, \tag{4.38b}$$

$$\text{CR}_{y,r} = \alpha_y \left| f_r(\lambda_{y,r} - \lambda_{x,r}) \right|, \tag{4.38c}$$

with

$$\alpha_x + \alpha_y = 1. \tag{4.38d}$$

where the $\text{CR}_{n,r}$ variables represent the congestion rent allocated to each country, which can be calculated per country through a weighted sum of the country-specific term (for $x$ or $y$). $\alpha_x$ and $\alpha_y$ are the respective sharing keys of each country, dependent on the type of cost-allocation method agreed upon[3]. It is also important to note that, unlike the others, **congestion rent as a surplus redistribution tool is implicitly used in all cost-allocation mechanisms**.

## 4.6. Creating the net SEW surface

Following the analytical framework, the Python-based model is constructed. The model is initialized via a configuration file that defines global and regime-specific parameters. The global parameters define:

[2] The equation from CID Article 4.4 is arg $\min_{P_{SH,n}} \sum_{j=1}^{NOH_n} \left|(P_j - P_{SH,n}) \cdot EF_j\right|$, which considers multiple (possibly more than 2) price zones, and an aggregation of all resultant external flows for calculating congestion income from a multi-flow environment.

[3] In this model, it is assumed that CR is always distributed according to the 50-50 split principle.

- Baseline interconnector capacity $K$
- Unit investment costs:
  - $c_{trans}$ (per MW interconnector)
  - $c_{radial}$ (per MW wind expansion)
- Strike prices for:
  - Transmission CfD
  - Generation CfD

Meanwhile the regime-specific parameters, for each of the $8$ regimes, per country ($x$ and $y$), include the choke price $\bar{\lambda}_n$, linear supply and demand curve slopes $a_{Dn}$ and $a_{Sn}$, and the baseline renewable capacities $q_{x,\text{RES}}$ and $q_{y,\text{RES}}$. Probability weight $\omega_r$ is also assigned exogenously in the initialization configuration. Finally, the range of considered expansion in wind and/or interconnector is encapsulated in a rectangular grid defined over $\Delta K$ and $\Delta q_{x,\text{RES}}$, in which all expansion combinations are evaluated.

After loading all primitives from the predefined configuration, the model solves all deterministic operating regimes using closed form expressions of the framework in section 4.2 - section 4.5. Each regime solution is filtered through a feasibility layer that ensures they are economically and physically consistent. The following conditions are imposed:

**General Conditions**
- $q_x, q_y \geq 0$
- $\lambda_x, \lambda_y \geq 0$
- $g_x, g_y \geq 0$
- $|f| \leq K + \Delta K$

**Regime-Specific Conditions**
- Uncongested $\rightarrow |f| < K$
- Export cong. $\rightarrow f = +K, \lambda_y \geq \lambda_x$
- Import cong. $\rightarrow f = -K, \lambda_x \geq \lambda_y$
- Wind dominance $g_x \approx 0$ or $g_y \approx 0$

Using Kristiansen et al. (2018)'s definition for net social economic welfare with its actor-specific surplus components, the model computes the net SEW for each feasible regime:

$$\text{NetSEW}_r = CS_x^r + CS_y^r + PS_x^r + PS_y^r + CR_r - C_{\text{radial}} - C_{\text{trans}} \tag{4.39}$$

where the actor-specific components are calculated as:

$$CS_x^r = \frac{1}{2} a_{Dx} \left(q_x^r\right)^2 \tag{4.40}$$

$$PS_x^r = \lambda_x^r g_x^r - \frac{1}{2} a_{Sx} \left(g_x^r\right)^2 \tag{4.41}$$

where $PS_x^{\text{disp},r}$ is the regime-specific dospl

(similarly for $y$)

Investment costs are deterministic and subtract from welfare:

$$C_{\text{radial}} = c_{\text{radial}}\, \Delta q_{x,\text{RES}} \tag{4.42}$$
$$C_{\text{trans}} = c_{\text{trans}}\, \Delta K \tag{4.43}$$

These are subtracted at the regime level. The expected system welfare at the expansion point is calculated via:

$$\mathbb{E}[\text{NetSEW}] = \sum_{r \in \text{feasible}} \tilde{\omega}_r \cdot \text{NetSEW}_r \tag{4.44}$$

Repeating over the full range of possible expansions (combinations of $\Delta K$ and $\Delta q_{\text{x,RES}}$) produces the system-level net SEW surface. This surface represents the expected total net social welfare of the integrated two-country electricity system as a function of joint expansion decisions in renewable generation and interconnection capacity. The system net SEW does not depend on cost-sharing mechanisms and represents the socially efficient benchmark with the global maxima of this surface corresponding to the first-best coordinated expansion outcome.

The system welfare is also interpreted as a sum of actor-level components. Therefore, for each regime $r$, country-level welfare can be defined as:

$$\text{NetSEW}^r = \text{NetSEW}^r_x + \text{NetSEW}^r_y \tag{4.45}$$

Country-level welfare, reflecting the elements of relevant cost-sharing mechanisms is, for countries $x$ and $y$ separately:

$$\text{NetSEW}^r_n = CS^r_n + PS^r_n + CR^r_n + CfD^r_{\text{trans}} + CfD^r_{\text{gen}} - C_n \tag{4.46}$$

Here consumer and producer surpluses are country specific. Shares of congestion rent, CfD transfer mechanisms part of the cost-sharing methods, and investment costs are assigned ex-ante according to the cost setting. Expected country welfare is defined analogously to system welfare:

$$\mathbb{E}[\text{NetSEW}_x] = \sum_{r \in \text{feasible}} \tilde{\omega}_r \cdot \text{NetSEW}^r_x \tag{4.47}$$

$$\mathbb{E}[\text{NetSEW}_y] = \sum_{r \in \text{feasible}} \tilde{\omega}_r \cdot \text{NetSEW}^r_y \tag{4.48}$$

# 4.7. Strategic expansion game

Each country seeks a different level of expansion along the grid, maximizing its own net social welfare. However, it is not necessarily the case that either country's individual welfare maximum, or the system-optimal point, corresponds to the expansion both countries would actually agree upon. To enable a common ground for comparison, a non-cooperative strategic expansion game is developed that identifies the set of mutually agreed expansion outcomes.

Two players (countries), $n \in \{x, y\}$, simultaneously propose expansion levels restricted to the same discrete grid of candidate expansions:

$$\Delta K \in \mathcal{K} = \{\Delta K_0, \ldots, \Delta K_I\}, \qquad \Delta q \in \mathcal{Q} = \{\Delta q_0, \ldots, \Delta q_J\} \tag{4.49}$$

Grid index $i$ denotes interconnector expansion $\Delta K$ (horizontal axis) and grid index $j$ denotes offshore wind expansion $\Delta q_{x,\text{RES}}$ (vertical axis).

Since both countries must agree for any investment to proceed, the implemented expansion cannot exceed the most conservative proposal on any jointly decided dimension. Formally, for a jointly decided dimension, the agreed outcome is determined by:

$$\text{agreed} = \min(\text{proposal}_x, \text{proposal}_y) \tag{4.50}$$

This is referred to as the *min-rule*: a country can always block or reduce an expansion by proposing a lower level, but cannot unilaterally force a higher level of investment than the other country is willing to accept.

Interconnector expansion is always a joint decision, as both countries share its costs. Country $x$ proposes $i_x \in \mathcal{K}$ and country $y$ proposes $i_y \in \mathcal{K}$, with the agreed interconnector expansion:

$$i = \min(i_x, i_y) \tag{4.51}$$

The treatment of offshore wind expansion depends on the cost-sharing configuration, which determines whether wind is a unilateral or bilateral decision:

- **Unilateral wind (interconnector costs only shared):** When country $y$ bears no share of radial connection costs and does not participate in a cross-border $\text{CfD}_{\text{gen}}$, wind expansion is decided solely by country $x$, which proposes $(i_x, j_x) \in \mathcal{K} \times \mathcal{Q}$. Country $y$ proposes only $i_y \in \mathcal{K}$. The agreed outcome is:

  $$i = \min(i_x, i_y), \qquad j = j_x \tag{4.52}$$

  In this setting, country $y$ can veto or reduce interconnector expansion via the min-rule, but has no influence over the level of offshore wind deployed by country $x$.
- **Bilateral wind (radial costs shared or $\text{CfD}_{\text{gen}}$ included):** When country $y$ bears a share of either radial connection costs or $\text{CfD}_{\text{gen}}$ payments, wind expansion becomes a joint decision. Both countries propose over both dimensions, with the min-rule applied on each:

  $$i = \min(i_x, i_y), \qquad j = \min(j_x, j_y) \tag{4.53}$$

  Here, either country can cap either dimension of the investment.

The payoff of each country is determined by the mechanism-adjusted net SEW evaluated at the agreed outcome $(i, j)$. Let $U_n(i, j)$ denote the expected net welfare of country $n$ at grid point $(i, j)$.

### 4.7.1. The negotiation space

The *negotiation space* is defined as the set of agreed expansion outcomes $(i, j)$ that constitute Nash equilibria of the non-cooperative game. A Nash equilibrium is an agreed outcome such that neither country can improve its payoff by unilaterally proposing a different expansion level (Sethi & Weibull, 2016). Formally, a pure-strategy Nash equilibrium $(i^*, j^*)$ satisfies:

$$U_x(i^*, j^*) \geq U_x(i, j) \qquad \forall (i, j) \text{ reachable by } x \text{ given } y\text{'s proposal} \tag{4.54}$$

$$U_y(i^*, j^*) \geq U_y(i, j) \qquad \forall (i, j) \text{ reachable by } y \text{ given } x\text{'s proposal} \tag{4.55}$$

Because the min-rule renders many proposal pairs payoff-equivalent, equilibria are reported directly as agreed outcomes rather than proposal pairs. At any such point, neither country can unilaterally move to a different expansion outcome. When multiple equilibria exist, the model selects the one with the highest combined welfare as a tie-breaking rule:

$$(i^\dagger, j^\dagger) \in \arg\max_{(i,j) \in \mathcal{E}} [U_x(i, j) + U_y(i, j)] \tag{4.56}$$

where $\mathcal{E}$ is the set of agreed equilibrium points. Figure 4.3 illustrates these concepts schematically. The negotiation space is shown as a collection of agreed expansion outcomes, with the welfare-maximizing equilibrium selected among them via the tie-breaking rule. The contour lines indicate levels of efficiency loss (see section 4.8 relative to the system-optimal expansion, making the welfare gap between the strategic outcome and the first-best benchmark directly visible.

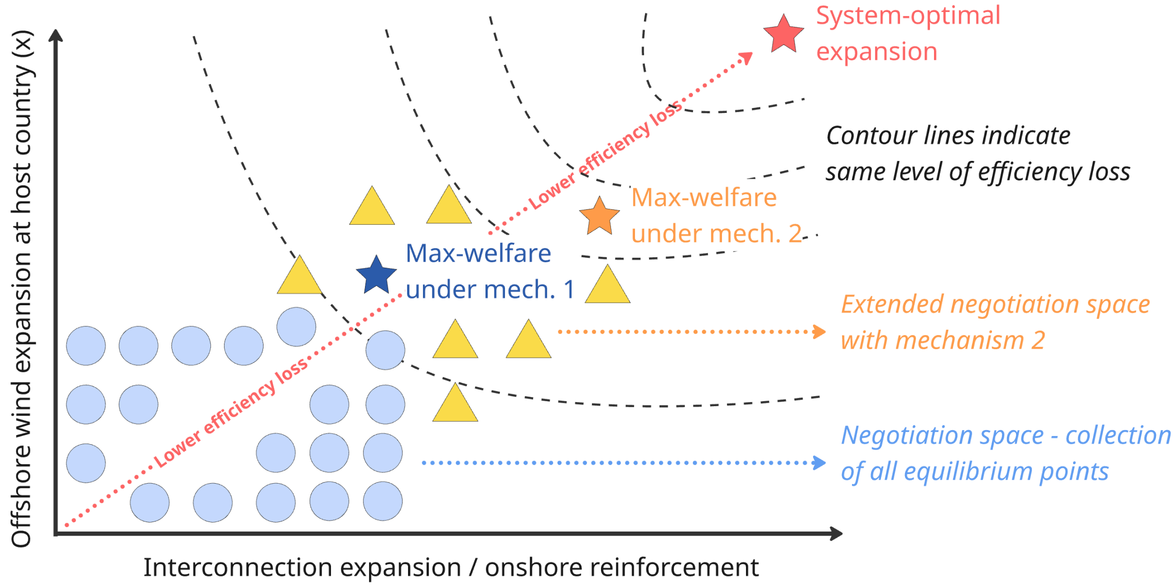



**Figure 4.3:** Schematic illustration of the negotiation space and efficiency loss concepts. Blue circles represent Nash equilibria under a baseline mechanism; yellow triangles show how an alternative mechanism extends this space toward higher expansion levels. The blue and orange stars mark each mechanism's welfare-maximizing equilibrium, while the red star indicates the system-optimal expansion. Dashed contour lines connect points of equal efficiency loss, decreasing in the direction of the dotted arrow. The gap between the welfare-maximizing equilibrium and the system optimum defines the efficiency loss.

Repeating this procedure across all considered cost-sharing mechanisms yields a set of equilibrium outcomes and associated performance metrics that form the basis of the comparative analysis in chapter 5.

## 4.8. Metrics

After results are obtained, they are subjected to two comparison metrics: efficiency loss and cost-benefit mismatch.

### Efficiency loss

Efficiency loss measures the welfare gap between the socially optimal (first-best) expansion and the expansion resulting from the strategic game.

$$\text{Efficiency Loss (\%)} = \frac{E[\text{NetSEW}(i^{SO}, j^{SO})] - E[\text{NetSEW}(i^{\dagger}, j^{\dagger})]}{E[\text{NetSEW}(i^{SO}, j^{SO})]}. \tag{4.57}$$

where $(i^{SO}, j^{SO})$ corresponds to point of system-optimal expansion. Lower this efficiency loss (in percentage) is, closer the strategic game has gotten to a system-optimal expansion (better outcome).

### Cost-benefit mismatch

Let country $x$'s share of capital costs be

$$\text{Cost Share}_x = \frac{C_x}{C^{\text{tot}}}. \tag{4.58}$$

Total realized economic benefits (excluding capital investment costs) are defined as

$$B^{\text{tot}} = \sum_{n \in \{x,y\}} B_n, \tag{4.59}$$

where $B_n$ includes consumer surplus, producer surplus, congestion rent shares, and CfD transfers, but excludes capital investment costs.

Country $x$'s benefit share is given by

$$\text{Benefit Share}_x = \frac{B_x}{B^{\text{tot}}}. \tag{4.60}$$

The cost–benefit mismatch for country $X$ is then defined as

$$\text{Mismatch}_x = \text{Cost Share}_x - \text{Benefit Share}_x = \frac{C_x}{C^{\text{tot}}} - \frac{B_x}{B^{\text{tot}}}. \tag{4.61}$$

A positive mismatch indicates that country $x$ pays a larger share of capital costs than the share of total economic benefits it realizes, while a negative mismatch implies a net redistributive gain. For comparative analysis, the absolute value of the mismatch is used. Mismatch for country $y$ is symmetrical to that of country $x$.

### The negotiation space as a metric

Beyond identifying welfare-maximizing expansion points, the model evaluates the *negotiation space* between the two countries as an additional performance metric for different cost-sharing mechanisms. The negotiation space refers to the set of expansion combinations $(\Delta K, \Delta q_{x,\text{RES}})$ for which both countries obtain non-negative net benefits relative to the baseline case without additional infrastructure. Formally, it consists of all points where

$$U_x(\Delta K, \Delta q_{x,\text{RES}}) \geq 0 \quad \text{and} \quad U_y(\Delta K, \Delta q_{x,\text{RES}}) \geq 0, \tag{4.62}$$

where $U_x$ and $U_y$ denote the net welfare gains for countries $x$ and $y$, respectively, after accounting for investment costs and transfers implied by the selected cost-sharing mechanism.

This region represents the set of mutually acceptable expansion outcomes that could, in principle, be supported by voluntary agreement between the two parties. A larger negotiation space indicates that a mechanism creates more opportunities for mutually beneficial cooperation, while a smaller space suggests a higher likelihood of bargaining failure or strategic disagreement. As such, the size and shape of the negotiation space provide an intuitive metric for evaluating how different cost-sharing mechanisms influence the feasibility of cross-border infrastructure expansion.

## 4.9. Simulation setup

This section outlines the simulation setup underlying the quantitative analysis. It first motivates the selection of model parameters and the construction of a stylized two-country setting, followed by a description of the deterministic operating regimes and the baseline conditions in subsection 4.9.1. Building on this foundation, the section introduces the sensitivity analyses conducted on regime weights in subsection 4.9.2 and CfD strike prices in subsection 4.9.3, which are used to assess the robustness of equilibrium outcomes under uncertainty in market conditions and regulatory design. Finally, subsection 4.9.4 examines how equilibrium outcomes respond to variation in unit investment costs, providing insight into the sensitivity of the results to the cost assumptions underlying the model.

### 4.9.1. Motivation for parameter selection

As a first step into analysis, a set of default parameters are established. To reflect differing positions and incentives for expansion, the model should incorporate a setting in which the two countries possess inherently different characteristics. Country $x$ is modeled as the renewable-rich, relatively flexible/lower-cost system, while country $y$ is modeled as more supply-constrained with steeper marginal costs, making it more dependent on interconnection to access low-cost energy.

According to Willems et al. (2025), countries whose wholesale electricity prices are more strongly affected by an increase in transmission capacity (steeper supply curve) tend to benefit proportionally more from that expansion. Thus, this differing position of two countries is reflected through a large difference between the supply curve slopes ($a_{S_y} >> a_{S_x}$). On the demand side, both countries were kept relatively similar with respect to the slopes, where they were tuned via trial-and-error to produce game results where the optimal expansion point would lie within the considered expansion grid. The choke price was used to determine the import or export status of each country- where a higher choke price implies that the market price remains higher over a larger range of quantities, which, together with the slope of the demand curve, influences the likelihood of a country acting as an importer or exporter. During the parameter selection process, it was observed that the renewable constraints—specifically the on/off status of dispatchable and renewable generation—together with the resulting import or export status, are primarily driven by the difference in available renewable generation between the two zones, i.e., $|q_{x,\text{RES}} - q_{y,\text{RES}}|$. For simplicity, scenarios in which one country dominates in renewable generation are modeled using fixed renewable injections of $5000$ MWh for $x$ and $3000$ MWh for $y$. The higher injection assigned to country $x$ reflects its role as the renewable-rich system in the model.

Numerical values for choke prices and supply/demand curve slopes are initialized with reference from *EPEX Spot*[4]. Although data is not meant to replicate real spot markets consistently, the general order of magnitude is on par with adjustments made to fit the linear supply and demand assumptions. The order of magnitude for injected renewable energy capacity—considering solar, onshore, and offshore wind—is based on data from internal sources indicative of the Netherlands, which broadly represents the wind-rich country modeled as $x$. Parameters used for the single run are summarized in Table 4.2.

**Table 4.2:** Deterministic operating regimes: parameters and weights

| ID | Code | $\omega_r$ [-] | $a_{Dx}$ [€/MWh$^2$] | $a_{Dy}$ [€/MWh$^2$] | $a_{Sx}$ [€/MWh$^2$] | $a_{Sy}$ [€/MWh$^2$] | $\lambda_x$ [€/MWh] | $\lambda_y$ [€/MWh] | $q_{x,\text{RES}}$ [MWh] | $q_{y,\text{RES}}$ [MWh] |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | L0G00x | 0.1667 | 1.0 | 1.1 | 10 | 50 | 6500 | 3000 | 5000 | 0 |
| 2 | L0G00y | 0.0833 | 1.0 | 1.1 | 10 | 50 | 3000 | 5000 | 0 | 3000 |
| 3 | L0G10 | 0.0833 | 1.0 | 1.1 | 10 | 50 | 6500 | 3000 | 5000 | 0 |
| 4 | L0G01 | 0.0417 | 1.0 | 1.1 | 10 | 50 | 3250 | 3000 | 0 | 3000 |
| 5 | L+G00 | 0.1667 | 1.0 | 1.1 | 10 | 50 | 4400 | 6500 | 5000 | 0 |
| 6 | L+G10 | 0.1667 | 1.0 | 1.1 | 10 | 50 | 4500 | 6500 | 5000 | 0 |
| 7 | L-G00 | 0.1667 | 1.0 | 1.1 | 10 | 50 | 5500 | 2500 | 0 | 3000 |
| 8 | L-G01 | 0.1250 | 1.0 | 1.8 | 10 | 50 | 5500 | 2500 | 0 | 3000 |

Alongside these parameters, baseline values for interconnector capacity (already existing capacity) as $K = 1700$ MW, transmission and radial connection cost per MW as $c_{\text{trans}} = 250$ €/MW and $c_{\text{radial}} = 1500$ €/MW respectively. These values were selected primarily following a trial-and-error process with the goal of ensuring results are visualized within the considered expansion grid.

Transmission CfD strike price of $\lambda^{\text{strike}}_{\text{trans}} = 5000$ €/MWh and generation strike price $\lambda^{\text{strike}}_{\text{gen}} = 2000$ €/MWh are selected. These contract parameters are not optimized to generate ideal results but rather are set as a starting point for an initial analysis- later experimented in subsection 4.9.3.

Finally, the policy makers (of the two hypothetical countries) consider a maximum $1100$ MWh of additional wind ($\approx 4400$ MW with a capacity factor of $0.25$) and $500$ MW of expansion of interconnector capacity ($\approx 30$% increase in total installed capacity). Each expansion is considered with a step size of $10$ MWh and $10$ MW for wind and interconnector capacity respectively. However, presented figures are truncated to the region bounded by the system-optimal expansion levels, such that the upper limits of both offshore wind capac-

[4]https://www.epexspot.com/en

ity and interconnector expansion correspond to the welfare-maximizing point in order to improve interpretability.

### 4.9.2. Sensitivity analysis - weights

Under conditions of perfect information and full foresight, a centralized planning model might be able to determine an optimal network configuration. However, in reality, future electricity demand and supply at each connection point remain uncertain, as climatic, economic, and other structural developments can significantly alter energy consumption patterns. As a result, the optimal level of network investment and the associated costs cannot be determined with certainty ex ante (Heussaff and Zachmann, 2025).

In the model, the regime weights represent the likelihood of different market outcomes and therefore reflect the two countries' expectations about future conditions. Since expected payoffs are constructed using these probabilities, the non-cooperative investment outcome inherently depends on such beliefs. This raises the question of how sensitive the equilibrium is to alternative assumptions regarding regime likelihood. To address this, a sensitivity analysis on the weights is conducted. The exercise is not testing arbitrary beliefs; it is testing plausible deviations around the baseline expectation structure. Weights used across the runs are provided in Table 4.3.

**Table 4.3:** Sample of regime probability weights used in the simulations

| Run | L0G00x | L0G00y | L0G01 | L0G10 | L-G00 | L-G01 | L+G00 | L+G10 |
|---|---|---|---|---|---|---|---|---|
| 1 | 0.194 | 0.095 | 0.015 | 0.138 | 0.109 | 0.088 | 0.196 | 0.166 |
| 2 | 0.165 | 0.038 | 0.000 | 0.074 | 0.086 | 0.328 | 0.129 | 0.180 |
| 3 | 0.245 | 0.016 | 0.013 | 0.088 | 0.136 | 0.211 | 0.105 | 0.186 |
| 4 | 0.146 | 0.070 | 0.041 | 0.041 | 0.122 | 0.124 | 0.194 | 0.262 |
| 5 | 0.228 | 0.087 | 0.064 | 0.057 | 0.125 | 0.129 | 0.243 | 0.066 |
| 6 | 0.101 | 0.147 | 0.062 | 0.091 | 0.047 | 0.149 | 0.228 | 0.175 |
| 7 | 0.179 | 0.125 | 0.043 | 0.110 | 0.163 | 0.176 | 0.062 | 0.143 |
| 8 | 0.163 | 0.104 | 0.002 | 0.118 | 0.216 | 0.086 | 0.219 | 0.093 |
| 9 | 0.212 | 0.091 | 0.007 | 0.036 | 0.159 | 0.091 | 0.086 | 0.317 |
| 10 | 0.189 | 0.025 | 0.008 | 0.043 | 0.153 | 0.097 | 0.319 | 0.166 |
| 11 | 0.173 | 0.112 | 0.024 | 0.082 | 0.229 | 0.050 | 0.163 | 0.168 |
| 12 | 0.141 | 0.023 | 0.036 | 0.203 | 0.111 | 0.062 | 0.128 | 0.296 |
| 13 | 0.132 | 0.029 | 0.035 | 0.070 | 0.135 | 0.175 | 0.257 | 0.167 |
| 14 | 0.146 | 0.134 | 0.090 | 0.121 | 0.084 | 0.109 | 0.116 | 0.200 |

This analysis provides insight into the stability of the comparative conclusions presented in chapter 5. Although equilibrium outcomes change mechanically when weights are adjusted, the relevant question is not whether any individual mechanism produces identical outcomes across all weight configurations, but whether the relative ordering of mechanisms — in terms of expansion levels, welfare outcomes, and cost-benefit alignment — remains consistent. If the ranking between mechanisms is preserved across weight configurations and the same mechanisms consistently emerge as welfare-superior or incentive-compatible, the comparative conclusions can be regarded as stable with respect to regime-likelihood assumptions.

To implement this analysis, 14 alternative weight vectors were sampled from a Dirichlet distribution[5], which is suitable because regime weights are probabilities that must be non-negative and sum to one (Probability Distribution Explorer, 2024). The distribution was centered on the baseline weights, ensuring that sampled vectors represent deviations

[5]The Dirichlet distribution is a multivariate probability distribution defined over vectors of non-negative values that sum to one. It generalizes the Beta distribution to K dimensions and is commonly used to model uncertainty over probability weights assigned to multiple mutually exclusive outcomes (Probability Distribution Explorer, 2024).

around the initial case. This approach aligns with the recommendation of European Commission (2022) to perform sensitivity analyses across 10-year network development plan (TYNDP) scenarios to strengthen the robustness and credibility of project assessments. Here, this reasoning is adapted to the simplified coupled-market framework by evaluating the stability of equilibrium outcomes under alternative regime-weight assumptions.

### 4.9.3. Sensitivity analysis - strike prices

In addition to regime-weight uncertainty, the model outcome also depends on the strike prices associated with the $\text{CfD}_{\text{trans}}$ and $\text{CfD}_{\text{gen}}$ instruments. These strike prices affect the distribution of net benefits and, consequently, strategic investment incentives. Since expected payoffs incorporate these transfers, the non-cooperative equilibrium will vary under alternative strike configurations. This raises the question of how sensitive the negotiated investment outcome is to the regulatory calibration of strike positions.

For mechanisms that employ CfDs, a sensitivity analysis is conducted over a grid of strike-price combinations while isolating the effect of strike design by keeping regime weights fixed at their baseline values in Table 4.2. The transmission strike price is varied over the range $[-40\%, +40\%]$ in increments of $10\%$ of the initial strike price of $\lambda_{\text{trans}} = 5000$ €/MWh. The generation strike price is varied over the range $[-25\%, +25\%]$ in increments of $5\%$ of the initial strike price of $\lambda_{\text{gen}} = 2000$ €/MWh. For $\text{CfD}_{\text{trans}}$-only mechanisms, only the transmission strike is swept (with $\text{CfD}_{\text{gen}}$ held fixed), whereas for mechanisms combining both, the full two-dimensional grid of strike pairs is evaluated[6].

If equilibrium outcomes remain concentrated in a similar expansion region across a range of strike levels, the mechanism can be regarded as not sensitive with respect to strike calibration. Conversely, if equilibrium locations shift substantially with modest strike adjustments, the mechanism's performance may be highly sensitive to policy design.

### 4.9.4. Sensitivity analysis - costs

In addition to uncertainty in regime weights and regulatory strike prices, the model outcomes are also influenced by the cost assumptions associated with interconnector expansion and radial connections. These cost parameters directly affect the distribution of net benefits and, consequently, the incentives for strategic investment. Since investment costs enter the payoff structure explicitly, the non-cooperative equilibrium may vary under alternative cost configurations, raising the question of how sensitive the negotiated outcome is to cost parameterization.

To assess this, a sensitivity analysis is conducted by varying interconnector unit costs $c_{\text{trans}}$ over the range $[100, 500]$ €/MW in increments of $50$ €/MW, and radial connection costs $c_{\text{radial}}$ over the range $[500, 2500]$ €/MW in increments of $250$ €/MW. Each cost parameter is varied independently while keeping the other fixed at its baseline value in Table 4.2, thereby isolating the effect of each cost component.

If equilibrium outcomes remain concentrated within a similar expansion region across a range of cost values, the mechanism can be considered not sensitive to cost uncertainty. Conversely, significant shifts in equilibrium locations indicate a strong dependence on cost assumptions and highlight potential sensitivities in the design of cost-sharing arrangements.

[6]This is done in order to save computational resources. Under mechanisms where $\text{CfD}_{\text{gen}}$ is not shared, it does not act as a cross-border transfer tool because only the TSO of country $x$ provides/receives from the OWF and there is no cross-border reallocation of incentives.

# 5

# Results: Analysis of Cost-Sharing Mechanisms

This chapter presents the results of the simulation analysis and evaluates how the different cost-sharing mechanisms affect negotiated infrastructure expansion between the two countries. The focus is on the size and structure of the negotiation space and the extent to which agreed expansions approach the welfare-maximizing solution.

The objective of the parametrization and simulation exercise is not to deliver precise, fully calibrated quantitative estimates or to assess the real-world feasibility of a specific project. Rather, the selected parameter values and simulation runs serve a stylized and illustrative purpose by enabling a controlled examination of how the cost-sharing mechanisms function and shape each country's strategic investment incentives.

Accordingly, the results of this analysis should be interpreted as mechanism comparisons rather than quantitative predictions. The absolute magnitudes of welfare changes, CfD transfers, and capital expenditures are artifacts of the chosen parameterization and carry no direct real-world meaning. What is meaningful is the relative performance of mechanisms against one another: whether one mechanism consistently produces equilibria closer to the system optimum, whether it expands or contracts the negotiation space, and how sensitive equilibrium outcomes are to varying market expectations. Readers should therefore focus on the patterns and rankings that emerge across mechanisms rather than on the specific numerical outcomes at any single equilibrium point

Table 5.1 provides a roadmap to the analysis that follows. Each section isolates a distinct cost-sharing configuration, building from the uncoordinated ex-ante baseline toward progressively richer combinations of ex-post instruments and broader cost scopes. The table summarizes the configuration examined in each section alongside its central finding, and serves as a reference point for navigating the detailed results presented in the remainder of the chapter.

**Table 5.1:** Overview of the cost-sharing configurations analysed in this chapter and their main findings.

| Section | Configuration analysed | Summary of findings |
|---|---|---|
| 5.1 | IC-only sharing; equal (50–50) vs. benefit-proportional (BP); no ex-post tool | Both ex-ante rules improve on no agreement, but the non-cooperative game underinvests relative to the system optimum. BP places equilibria closer to the optimum than the equal split, though outcomes are highly sensitive to regime-weight assumptions. |
| 5.2 | IC-only (50–50), with vs. without ex-post $\mathrm{CfD_{trans}}$ | Adding $\mathrm{CfD_{trans}}$ redistributes realised benefits without changing total welfare, steepening the equilibrium line and shifting the best-case equilibrium markedly closer to the optimum. Effectiveness is highly sensitive to the chosen strike price. |
| 5.3 | IC-only (50–50), with vs. without ex-post $\mathrm{CfD_{gen}}$ | Sharing $\mathrm{CfD_{gen}}$ turns the negotiation space from a line into a surface and raises offshore wind deployment, but yields only limited efficiency and mismatch gains — smaller benefits than $\mathrm{CfD_{trans}}$ — while exposing the non-host country to host-side market risk. |
| 5.4 | BP + $\mathrm{CfD_{gen}}$; IC-only vs. IC+radial cost scope | Broadening the shared cost base to radial connections under the BP key improves both efficiency and distributional alignment, the best overall performance among the tested mechanisms, as the key re-calibrates to realised benefits. |
| 5.5 | IC-only (50–50) + $\mathrm{CfD_{trans}}$ + $\mathrm{CfD_{gen}}$ | Combining both ex-post tools expands the feasible set from a line into a broad region and brings equilibria close to the optimum. Adding $\mathrm{CfD_{gen}}$ on top of $\mathrm{CfD_{trans}}$ does not raise the agreed investment level; the instruments follow different logics (bilateral transfer vs. joint outward subsidy to the OWF). |

# 5.1. Effect of ex-ante coordination

This section examines the outcomes of offshore wind and interconnector expansion in the absence of coordination, focusing on how different ex-ante cost-sharing rules affect efficiency and fairness. In particular, the equal (50–50) and benefit-proportional allocations are compared to assess the trade-off between simplicity and alignment with realized benefits.

Figure 5.1 illustrates the expected system welfare landscape and the resulting strategic equilibria under IC-only cost sharing for both equal (50–50) and benefit-proportional (BP) allocations. The plots highlight how different cost-sharing rules shape the location and structure of equilibrium outcomes relative to the welfare-maximizing expansion. Table 5.2 provides a decomposition of selected equilibrium outcomes, including changes in consumer surplus (CS), producer surplus (PS), congestion rents (CR), and investment costs for each country (CAPEX). Finally, Table 5.3 summarizes the overall efficiency and distributional performance of the two mechanisms through a direct comparison in terms of efficiency loss and mismatch.

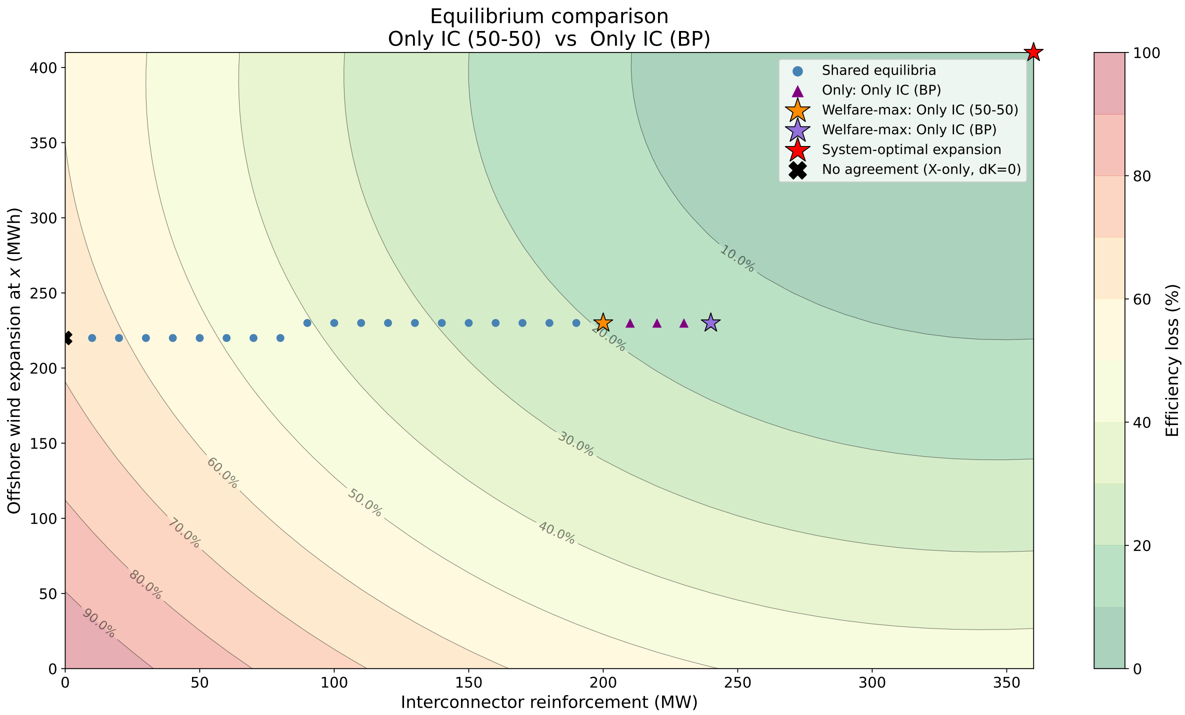



**Figure 5.1:** Strategic equilibria and efficiency loss landscape under ex-ante-only IC cost sharing, comparing equal (50–50) and benefit-proportional (BP) allocation rules. Neither mechanism includes an ex-post correction instrument. The background contours indicate the efficiency loss relative to the system-optimal expansion (red star). Blue circles denote expansion points that are Nash equilibria under both mechanisms; purple triangles indicate points that are equilibria exclusively under the BP allocation. Orange and purple stars mark the welfare-maximizing equilibria under the 50–50 and BP mechanisms respectively. The black cross indicates the no-agreement outcome, where only country $x$ invests unilaterally and no interconnector expansion occurs. Figure is truncated at the welfare-maximizing expansion level.

**Table 5.2:** Equilibrium outcomes and welfare decomposition by mechanism (Only IC (50–50) and Only IC (BP)); values in k€)

| Mechanism | $\Delta K$ | $\Delta q_{x,\text{RES}}$ | Country | $\Delta CS$ | $\Delta PS$ | $\Delta CR$ | CAPEX | ΔCfD trans | ΔCfD gen | $\alpha$ |
|---|---|---|---|---|---|---|---|---|---|---|
| No agreement | 0 | 220 | X | 505 | -80 | 10 | -330 | 0 | -4 | 1.000 |
| | | | Y | 53 | -42 | 10 | 0 | 0 | 0 | 0.000 |
| Only IC (50–50) | 200 | 230 | X | 432 | 221 | -49 | -370 | 0 | -3 | 0.500 |
| | | | Y | 93 | 193 | -49 | -25 | 0 | 0 | 0.500 |
| Only IC (BP) | 240 | 230 | X | 415 | 282 | -57 | -371 | 0 | -3 | 0.433 |
| | | | Y | 104 | 240 | -77 | -34 | 0 | 0 | 0.567 |

**Table 5.3:** Efficiency and distributional performance comparison (Only IC: 50–50 vs BP)

| **Mechanism** | **Efficiency Loss [%]** | **Mismatch [%]** |
|---|---|---|
| Only IC (BP) | 14.48% | 21.14% |
| Only IC (50–50) | 19.35% | 22.00% |

Even in the absence of coordinated offshore wind and/or interconnection development, cross-border leakage effects are clearly observed. Country $x$ invests unilaterally, driven solely by its own benefits, resulting in an additional $220$ MWh of wind generation injected into the system. This expansion leads to a positive increase in consumer surplus (by € +53,067 ) and congestion rent (by € +9,917 ) for country $y$, while its producer surplus decreases (by € -42,328 ). Overall, this results in a net benefit of € +20,656 for country $y$, corresponding to approximately 11% of the total net benefits generated by the unilateral investment in offshore wind by country $x$. According to European Commission (2025a), country $y$ should contribute to the project costs, as its net benefits exceed the minimum threshold of 10% of total net benefits created by the project. In the absence of a cost-sharing arrangement, country $y$ effectively free-rides on the investment made by country $x$.

Compared to no agreement (indicated with black cross in both plots in Figure 5.1), which represents no reinforcement to the onshore grid for coupling markets $x$ and $y$ further, both methods of cost-sharing arrangements yielded more optimal results. Onshore grid reinforcements, in the form of market-coupling interconnectors, can facilitate further investment in offshore wind by enabling a larger share of higher-value demand to be supplied with low-cost electricity. As illustrated in Table 5.2, increased interconnection capacity supports greater levels of offshore wind deployment even when the costs of offshore wind are not shared cross-border. From country $x$'s standpoint, bearing the full cost of offshore wind expansion, additional wind capacity following expanded interconnection makes sense when the gains created by the expanded interconnector (combined with additional wind) create a net positive investment outcome as the decision making algorithm aggregates all benefits.

Across both cost settings, the non-cooperative game leads to underinvestment relative to the socially efficient benchmark (purple star vs. red star). This inefficiency, numerically evaluated in Table 5.2, arises from cost internalization asymmetry and the varying distributional effects across the two countries. Inevitably, the Nash game "limits" the expansion possible under cooperation. As provided in Table 5.2, resultant expansion leads to a more optimal result by approximately 5% in the BP configuration. This is because the share of costs borne by each player reflects their real accrued benefits more accurately in the BP setting compared to a fixed 50-50 split. However, the resulting mismatch at equilibrium (21.14%) is marginally higher than under the 50-50 split (19.60%) because only a fraction of total costs are shared and leaking benefits of offshore wind distort the allocation under aggregated sharing keys.

A final observation is the reduction of CfD generation payouts (to the OWF) following increased interconnector capacity as can be seen in Table 5.2. The magnitude of generation CfD payments is determined by the difference between the strike price and the realized market price at country $x$:

$$\mathrm{CfD}^{\mathrm{gen}} \sim \left(\lambda^{\mathrm{gen}}_{\mathrm{CfD}} - \lambda_{x,r}\right)\, \Delta q_{x,\mathrm{RES}}. \tag{5.1}$$

An increase in interconnector capacity $\Delta K$ reduces congestion and improves price convergence the two market prices. As a result, the price in the exporting (wind) zone increases:

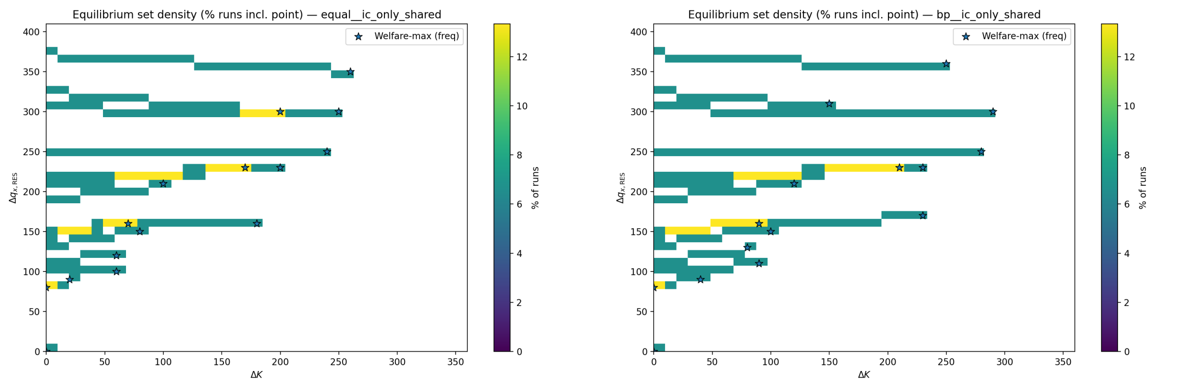
$$\Delta K \uparrow\ \Rightarrow\ \ \lambda_{x,r} \uparrow . \tag{5.2}$$

This leads to a reduction in the strike–price spread:

$$\left(\lambda^{\mathrm{gen}}_{\mathrm{CfD}} - \lambda_{x,r}\right) \downarrow, \tag{5.3}$$

and therefore lowers the magnitude of CfD payments. In regimes where $\lambda_{x,r} > \lambda^{\mathrm{gen}}_{\mathrm{CfD}}$, the payment reverses direction, resulting in net paybacks. Hence, greater interconnection reduces the need for generation-based CfD support by increasing market revenues for offshore wind.

In Figure 5.2 weight-based sensitivity analysis results are shown in order to assess the sensitivity of equilibrium outcomes to regime-weight assumptions (see subsection 4.9.2). This also helps test the general applicability of the findings.




**(a)** Equal (IC-only shared) **(b)** Benefit-proportional (IC-only shared)

**Figure 5.2:** Equilibrium set density across runs for equal and benefit-proportional cost-sharing under IC-only cost allocation. Colors indicate the percentage of runs in which a given point is part of the equilibrium set. Stars denote welfare-maximizing equilibria frequency. The figures are truncated at the welfare-maximizing expansion levels.

Under both cost settings, the equilibrium outcomes are highly sensitive to changes in regime weights. Although some recurring regions can be identified, these remain relatively narrow and fragmented. In both configurations, the share of runs in which any given expansion point is part of the equilibrium set peaks at only 7–8%, indicating that no single equilibrium region dominates consistently across alternative weight assumptions. The equilibrium outcome therefore depends materially on how the countries assess the likelihood of future market states.

Overall, the sensitivity results suggest that the ex-ante cost allocation mechanism produces equilibrium outcomes that are strongly conditioned on regime-weight assumptions. Within this sensitivity, however, the benefit-proportional allocation consistently produces equilibrium outcomes closer to the system-optimal expansion than the equal split across runs.

## 5.2. Effect of transmission CfD

This section examines the effect of introducing a transmission-based contract-for-difference ($\text{CfD}_{\text{trans}}$) as an ex-post redistribution mechanism on equilibrium investment outcomes. The analysis focuses on how the addition of $\text{CfD}_{\text{trans}}$ alters strategic incentives between countries without affecting total system welfare. The equal (50–50) allocation is considered with and without the CfD to isolate the impact of the ex-post correction. The comparison highlights how redistributing realized benefits influences the location of equilibria and the extent to which higher levels of interconnection and offshore wind expansion can be sustained.

Figure 5.3 illustrates how the introduction of the transmission CfD alters the location and structure of strategic equilibria under equal cost sharing. Table 5.4 quantifies the resulting changes in country-level welfare components and highlights the role of CfD transfers in redistributing gains between countries. Finally, Table 5.5 provides a summary comparison of overall performance.

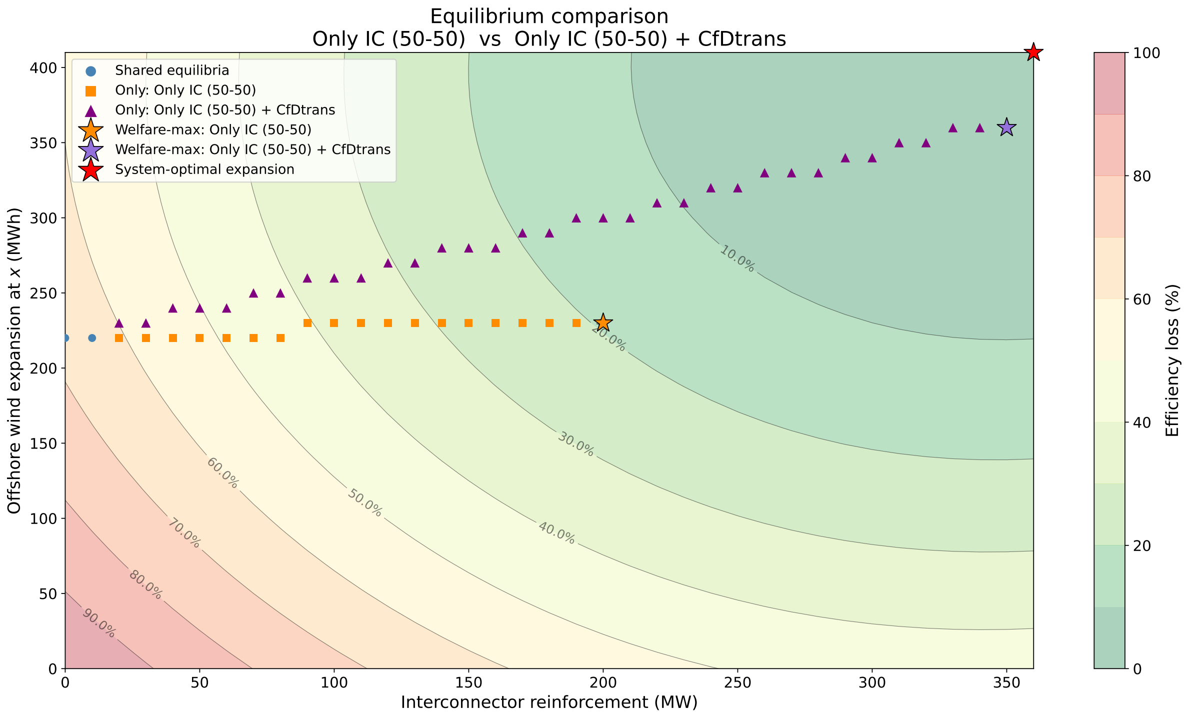



**Figure 5.3:** Strategic equilibria and efficiency loss landscape comparing the ex-ante-only IC (50–50) mechanism with and without the addition of an ex-post CfD$_{\text{trans}}$. Background contours indicate efficiency loss relative to the system-optimal expansion (red star). Orange squares and purple triangles denote equilibria exclusive to each mechanism respectively; blue circles are shared. Corresponding stars mark each mechanism's welfare-maximizing equilibrium. Figures are truncated at the welfare-maximizing expansion levels.

**Table 5.4:** Equilibrium outcomes and welfare decomposition by mechanism (50–50; values in k€)

| Mechanism | $\Delta K$ | $\Delta q_{x,\text{RES}}$ | Country | $\Delta CS$ | $\Delta PS$ | $\Delta CR$ | CAPEX | ΔCfD trans | ΔCfD gen | $\alpha$ |
|---|---|---|---|---|---|---|---|---|---|---|
| Only IC (50–50) | 200 | 230 | X | 432 | 221 | -49 | -370 | 0 | -3 | 0.500 |
| | | | Y | 93 | 193 | -49 | -25 | 0 | 0 | 0.500 |
| Only IC (50–50) + CfD$_{\text{trans}}$ | 350 | 360 | X | 685 | 371 | -121 | -584 | 88 | -38 | 0.500 |
| | | | Y | 175 | 346 | -121 | -44 | -88 | 0 | 0.500 |

**Table 5.5:** Efficiency and distributional performance comparison (Only IC: 50–50 vs 50–50 + CfD$_{\text{trans}}$)

| **Mechanism** | **Efficiency Loss [%]** | **Mismatch [%]** |
|---|---|---|
| Only IC (50–50) + CfD$_{\text{trans}}$ | 0.72% | 17.08% |
| Only IC (50–50) | 19.35% | 19.60% |

In the absence of an ex-post tool with only interconnector costs being shared, the Nash equilibria lie on a relatively flat wind path ($220$-$230$ MWh of $\Delta q_{x,\text{RES}}$). Introducing the CfD$_{\text{trans}}$, the line formed by the equilibria points becomes steeper and shifts the best-case equilibrium point (purple) closer to the optimal expansion point by $150$ MW of interconnection and $130$ MWh of wind. Although wind expansion does not fully internalize cross-border benefits, the transmission-based CfD indirectly provides incentive for $x$ to invest more into wind, which can be attributed to gains from CfD transfers from $x$ to $y$ partially overcoming losses from unilateral wind expansion. In terms of performance, the CfD$_{\text{trans}}$ is able to achieve a lower efficiency loss (approximately 18%) and a lower mismatch as indicated in Table 5.5. The ex-post correction yields significantly greater performance overall in achieving a system-efficient investment outcome.

Figure 5.4 shows the weight-based sensitivity analysis results for the IC-only 50–50 + CfD$_{\text{trans}}$ mechanism.

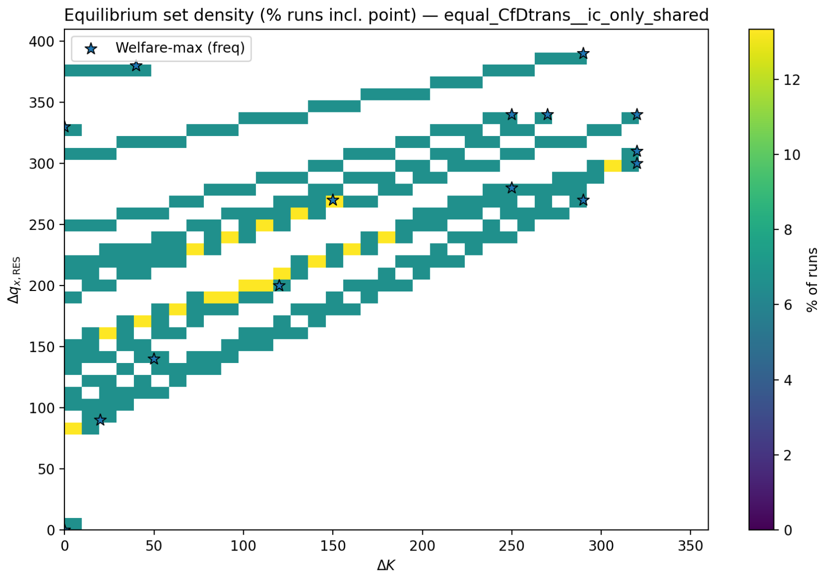



**Figure 5.4:** Equilibrium set density for the 50–50 + CfD$_{\text{trans}}$ mechanism under IC-only cost sharing. The color scale indicates the percentage of runs supporting a given equilibrium point, while stars denote welfare-maximizing outcomes. The figures are truncated at the welfare-maximizing expansion levels.

When CfD$_{\text{trans}}$ is introduced on top of this structure, the equilibrium outcomes begin to appear as upward-sloping combinations of $(\Delta K, \Delta q_{x,\text{RES}})$. This reflects the structural change already observed in the baseline analysis. In that case, it was shown that a transmission CfD indirectly incentivizes further unilateral wind expansion: the import-heavy country compensates the exporter, placing it in a better-off position compared to the no-compensation case. This increases the willingness to support greater interconnector expansion, which in turn raises the value of offshore wind and leads to further wind deployment. Observing this same pattern across multiple simulation runs reinforces the interpretation that transmission CfDs introduce a systematic change in expansion incentives, which consistently leads to more-system-efficient investment outcomes.

It can be said that the transmission CfD primarily changes the geometry of the equilibrium distribution across weight configurations rather than its overall size. The sensitivity analysis therefore confirms that the transmission CfD consistently reinforces the complementarity between offshore wind generation and cross-border transmission capacity, although it is not designed for this particular purpose.

Beyond how equilibrium outcomes shift across weight configurations, the design of the ex-post CfD$_{\text{trans}}$ is also dependent on a critical ex-ante parameter: $\lambda^{\text{strike}}_{\text{trans}}$. The results from the analysis in Figure 5.5 provides insight into the design of the CfD$_{\text{trans}}$ and shows how dependent efficient investment outcomes are to the strike price. Here the strike price for the CfD is varied through the range $[-40\%, +40\%]$ of the initial strike price with increments of $10\%$ in each iteration.

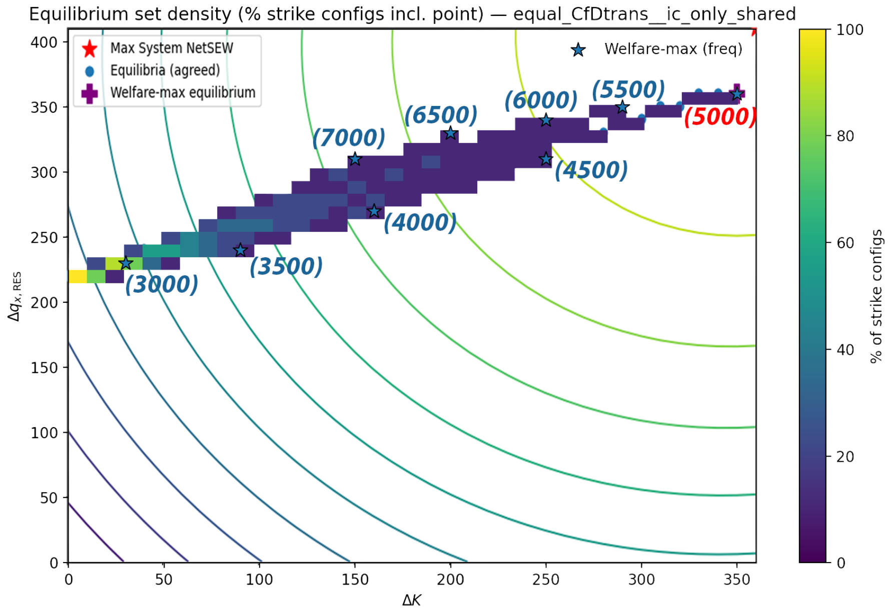



**Figure 5.5:** Equilibrium set density for the 50–50 + CfD$_{\text{trans}}$ mechanism under IC-only cost sharing. Each cell corresponds to an expansion configuration ($\Delta K$, $\Delta q_{\text{RES}}$); the value reports the percentage of swept strike-price configurations for which that point is part of the equilibrium set, so higher (darker) cells are equilibria that are persistent across a wider range of strike prices. The strike price labeled in red (5000 €/MWh) is the baseline/default value used elsewhere in the analysis, shown for reference against the swept range. Background contours represent the efficiency loss levels as in the equilibrium comparison figures. The axes are truncated at the welfare-maximizing expansion levels.

Increasing the strike price from $3000$ to $5000$ €/MWh leads to a noticeable shift of the welfare-maximizing equilibrium towards the system-optimal expansion. At lower strike price levels (approximately $3000$–$3500$), the resulting equilibrium outcomes perform worse than those obtained under the 50–50 IC-only ex-ante mechanism, indicating that the CfD$_{\text{trans}}$ is not effective in correcting the initial allocation at that setting. As the strike price increases, the agreed levels of wind and interconnection expansion progressively move closer to the system-optimal point. However, beyond a strike price of around $5000$ €/MWh, further increases reduce the effectiveness of the CfD$_{\text{trans}}$ as a redistributive instrument, which leads to increased efficiency loss between equilibrium outcomes and the system-optimal expansion. Table 5.6 shows the changing sign and magnitude of the compensation across the range of strike prices considered.

**Table 5.6:** CfD$_{\text{trans}}$ transfers across strike price levels (values in k€)

| **Strike Price [€/MWh]** | **Transfer (k€)** | **Direction** |
|---|---|---|
| 3000 | 10 | $x \to y$ |
| 3500 | 18 | $x \to y$ |
| 4000 | 12 | $x \to y$ |
| 4500 | 19 | $y \to x$ |
| 5000 | 88 | $y \to x$ |
| 5500 | 106 | $y \to x$ |
| 6000 | 120 | $y \to x$ |
| 6500 | 118 | $y \to x$ |
| 7000 | 103 | $y \to x$ |

The most system-aligned outcome occurs around a strike price of approximately $5000$ €/MWh, rather than at the highest transfer levels, because the strike price affects not only the magnitude of transfers but also the equilibrium that is selected. For each strike price, country payoffs are recomputed and the welfare-maximizing equilibrium is chosen among the agreed outcomes, such that $\Delta K$, $\Delta q_{x,\text{RES}}$, prices, and flows all adjust endogenously with the strike. Around $5000$, the $\text{CfD}_{\text{trans}}$ is effectively calibrated as a corrective mechanism. For higher strike prices, the direct effect of increasing the strike continues to raise transfers initially. However, beyond $5000$ €/MWh, the endogenous equilibrium adjustment begins to dominate: the selected equilibrium shifts toward lower $\Delta K$ and $\Delta q_{x,\text{RES}}$, reducing both the interconnector scaling term $\frac{\Delta K}{K_{\text{ref}}}$ and the export-weighted flow component $\sum_r \omega_r f_r$. As these terms decline, they outweigh the benefit of further increases in the strike price, causing transfers to decrease despite the higher strike. This explains why transfers peak at higher strike levels (around $6000$), while the best alignment with the system-optimal expansion is achieved earlier, around $5000$.

Two key insights emerge from this analysis. First, for a given ex-ante cost-sharing configuration, there exists a range of strike prices that enables the $\text{CfD}_{\text{trans}}$ to provide the necessary cross-border compensation to improve upon the initial allocation. While it is not guaranteed that any strike price will reproduce the system-optimal expansion, appropriately chosen values can still enhance the alignment of incentives and support higher levels of interconnection and offshore wind deployment, as observed in this case. This is in line with the conclusions Kristiansen et al. (2018), who presented this CfD for transmission as an instrument correcting imperfect ex-ante allocations to achieve ideal distribution of costs.

Second, the effectiveness of the $\text{CfD}_{\text{trans}}$ is highly sensitive to its design. In particular, an incorrectly specified strike price can lead to suboptimal—or even worse—outcomes relative to the ex-ante benchmark. The instrument is therefore not a plug-and-play solution; rather, it must be carefully calibrated to reflect country-specific characteristics and expected future market conditions.

## 5.3. Effect of cross-border CfD for generation

This section examines the effect of introducing a cross-border $\text{CfD}_{\text{gen}}$ on investment outcomes and negotiation dynamics under IC-only cost sharing. The analysis focuses on how sharing generation-related payments alters incentives for offshore wind deployment and interconnection expansion relative to an ex-ante-only setting. Once again, the equal (50–50) split is used as a benchmark to isolate the impact of $\text{CfD}_{\text{gen}}$.

Figure 5.6 and the accompanying tables present the resulting equilibrium outcomes under the inclusion of $\text{CfD}_{\text{gen}}$, alongside the baseline case for comparison.

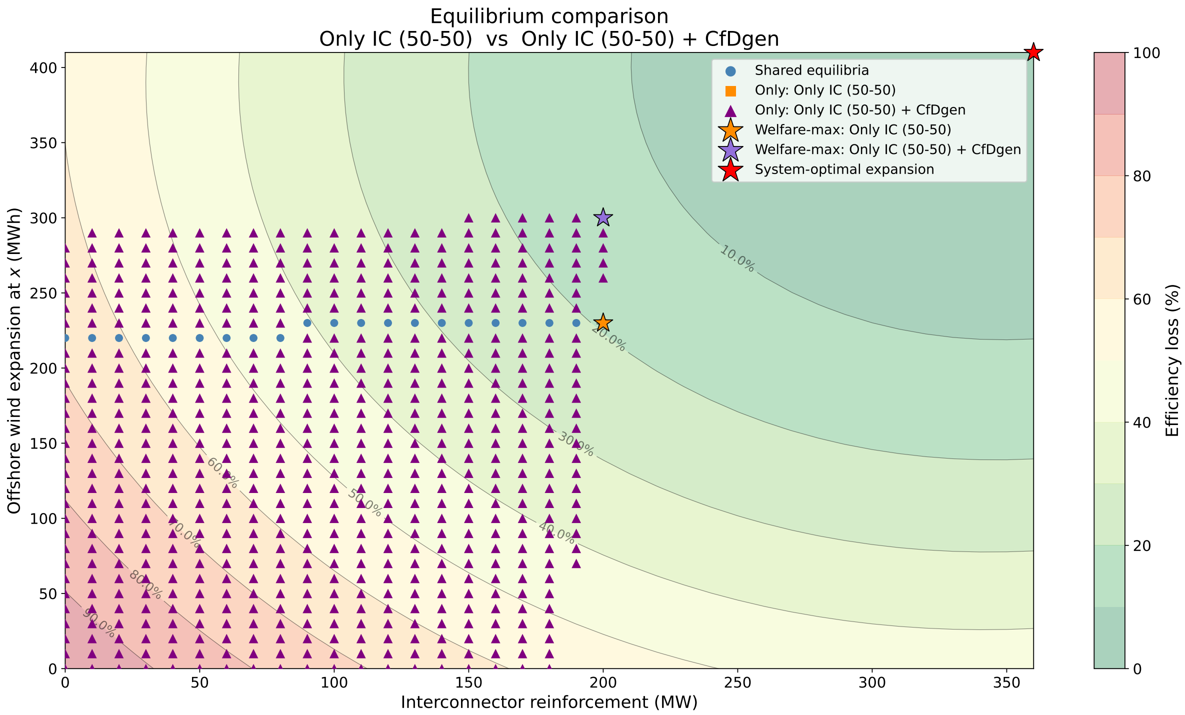



**Figure 5.6:** Strategic equilibria and efficiency loss landscape comparing the ex-ante-only IC (50–50) mechanism with and without the addition of an ex-post $\text{CfD}_{\text{gen}}$. Background contours indicate efficiency loss relative to the system-optimal expansion (red star). Orange squares and purple triangles denote equilibria exclusive to each mechanism respectively; blue circles are shared. Corresponding stars mark each mechanism's welfare-maximizing equilibrium. Figures are truncated at the welfare-maximizing expansion levels.

**Table 5.7:** Equilibrium outcomes and welfare decomposition by mechanism (50–50; values in k€)

| Mechanism | $\Delta K$ | $\Delta q_{x,\text{RES}}$ | Country | $\Delta CS$ | $\Delta PS$ | $\Delta CR$ | CAPEX | ΔCfD trans | ΔCfD gen | $\alpha$ |
|---|---|---|---|---|---|---|---|---|---|---|
| Only IC (50–50) | 200 | 230 | X | 432 | 221 | -49 | -370 | 0 | -3 | 0.500 |
| | | | Y | 93 | 193 | -49 | -25 | 0 | 0 | 0.500 |
| Only IC (50–50) + $\text{CfD}_{\text{gen}}$ | 200 | 300 | X | 599 | 180 | -45 | -475 | 0 | -10 | 0.500 |
| | | | Y | 111 | 179 | -45 | -25 | 0 | -10 | 0.500 |

**Table 5.8:** Efficiency and distributional performance comparison (Only IC: 50–50 vs 50–50 + $\text{CfD}_{\text{gen}}$)

| **Mechanism** | **Efficiency Loss [%]** | **Mismatch [%]** |
|---|---|---|
| Only IC (50–50) + $\text{CfD}_{\text{gen}}$ | 14.22% | 19.54% |
| Only IC (50–50) | 19.35% | 19.60% |

As illustrated in Figure 5.6, moving from an ex-ante-only setting to one in which generation CfD costs are also shared transforms the negotiation space from a one-dimensional line into a two-dimensional surface. This reflects the fact that decision-making now requires the agreement of country $y$, as it also bears part of the cost of supporting the offshore wind farm.

Table 5.7 shows that the inclusion of $\text{CfD}_{\text{gen}}$ leads to a substantial increase in offshore wind deployment, while leaving interconnection expansion unchanged. This higher level of wind expansion is accompanied by increased capital expenditure in country $x$, which continues to bear the full cost of the radial connection to shore. Since country $x$ is now responsible for only half of the CfD payouts, the net benefit of offshore wind investment improves for $x$, enabling it to undertake greater infrastructure investment. This is driven by gains in consumer surplus (€ +166,665) and increased congestion rents (€ +3,526), which together outweigh the total losses (€ -152,912) incurred by country $x$. Country $y$ is similarly willing to participate in the CfD payments. Although its producers are negatively affected by the additional wind capacity, its consumers benefit from lower prices and its TSO gains from higher congestion rents resulting from the increased level of wind deployment. These gains are sufficient to justify its contribution to the CfD mechanism.

Additionally, total CfD payouts to the OWF has increased by € 17,168 due to more wind capacity being built. López Prol, Steininger, and Zilberman (2020) suggests more renewable penetration to the energy mix causes the so-called self-cannibalization effect[1]. One would expect that lower wholesale prices would result in higher payouts to the OWF, particularly in the absence of interconnector expansion, which would otherwise mitigate this effect as discussed in section 5.1. However, the total CfD payout is determined by two factors: the spread between the strike price and the realized market price, and the total quantity of wind generation receiving that spread. While the self-cannibalization effect pushes wholesale prices down, which would widen the spread and increase the per-unit payout, this price decline turns out to be modest in magnitude. The dominant effect is therefore the increase in the total quantity of wind generation: more MWh are now being produced, each receiving a CfD payout, and this volume increase is large enough to raise total CfD payments even without a substantial widening of the per-unit spread.

From a performance perspective, Table 5.8 indicates a modest improvement in efficiency relative to the baseline case, of approximately 5%. In this scenario, the implementation of the cross-border CfD improves the investment outcome, as country $y$ derives relatively higher value from additional wind deployment than country $x$. This supports further expansion of offshore wind capacity beyond $230$ MWh up to $300$ MWh. In terms of mismatch, both mechanisms perform similarly, indicating that the introduction of $\text{CfD}_{\text{gen}}$ as a cost component for both countries did not significantly improve the alignment between costs and benefits, most likely due to the relatively small size of the absolute payout to the OWF compared to other larger cost components such as CAPEX and surplus losses. Compared to the transmission CfD, the generation CfD yields limited gains in overall efficiency and fairness. The primary structural effect of introducing $\text{CfD}_{\text{gen}}$ is the transformation of the negotiation space from a single equilibrium line into a broader set of feasible outcomes. This expanded negotiation space allows for a wider range of infrastructure development options that can satisfy both countries.

In Figure 5.7, the weight-based sensitivity analysis results for the IC-only 50–50 + $\text{CfD}_{\text{gen}}$ mechanism is shown.

[1] An increasing share of zero marginal cost variable renewable energy sources leads to lower wholesale electricity prices through the merit-order effect. This results in a "cannibalization effect," whereby higher levels of renewable penetration reduce the market value of the renewable generation itself (López Prol et al., 2020).

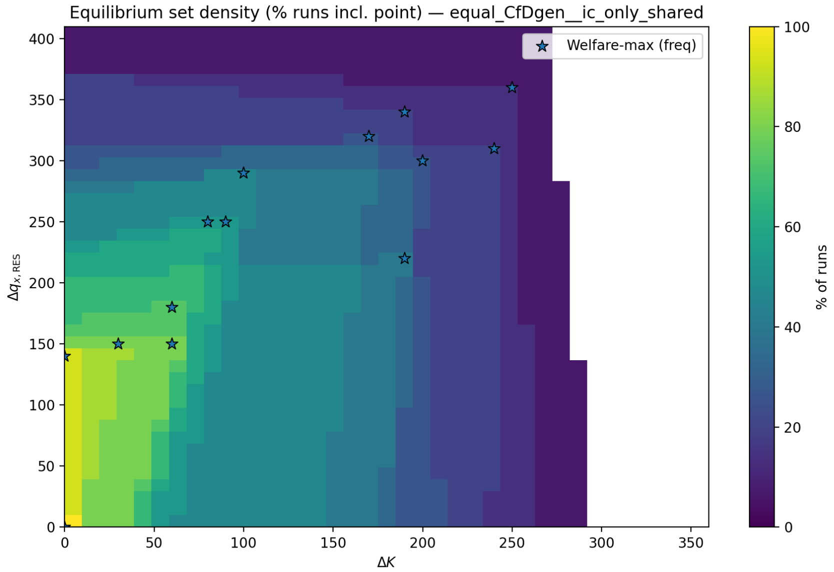



**Figure 5.7:** Equilibrium set density for the Equal + $\text{CfD}_{\text{gen}}$ mechanism under IC-only cost sharing. The color scale indicates the percentage of runs supporting a given equilibrium point, while stars denote welfare-maximizing outcomes. The figures are truncated at the welfare-maximizing expansion levels.

Compared to the ex-ante-only setting, the introduction of $\text{CfD}_{\text{gen}}$ results in a broader and more continuous equilibrium region, indicating that a wider range of expansion combinations can be sustained across different weight configurations. However, the distribution of equilibria remains highly concentrated in the lower-to-mid range of interconnection and wind expansion. Higher levels of expansion, including those closer to the welfare-maximizing outcomes, are supported in only a limited number of runs, as indicated by the low density of equilibrium points in these regions. This suggests that, while the mechanism expands the feasible negotiation space, it does not substantially improve the consistency of higher investment levels across weight configurations. Overall, the results indicate that the inclusion of $\text{CfD}_{\text{gen}}$ increases the flexibility of feasible outcomes but does not significantly stabilize equilibrium selection. The equilibrium remains sensitive to assumptions on regime weights, with most realizations clustering around moderate expansion levels rather than converging toward the welfare-maximizing solution.

Beyond how equilibrium outcomes vary with changing weight assumptions, the performance of the ex-post $\text{CfD}_{\text{gen}}$ mechanism is influenced by a key ex-ante design parameter: the strike price $\lambda_{\text{gen}}^{\text{strike}}$. The results presented in Figure 5.8 provide insight into how the choice of strike price affects investment outcomes and the distribution of equilibria. In this analysis, the generation CfD strike price is varied over the range $[-25\%, +25\%]$ with increments of $5\%$.

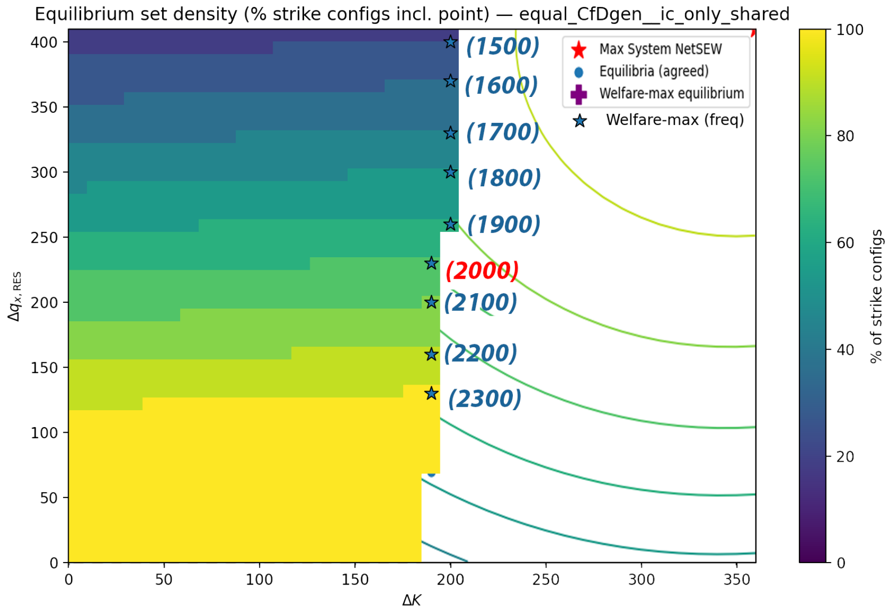



**Figure 5.8:** Equilibrium set density for the Equal + CfD$_{\text{gen}}$ mechanism under IC-only cost sharing. The shaded heatmap gives, for each expansion configuration ($\Delta K$, $\Delta q_{x,\text{RES}}$), the percentage of swept strike-price configurations for which that point belongs to the equilibrium set; brighter (yellow) cells therefore mark expansion points that remain equilibria across a wider range of strike prices. Dark-blue stars mark the welfare-maximizing equilibrium (by frequency across the sweep), each labelled with its associated strike price [€/MWh]; the label shown in red (2000 €/MWh) is the baseline/default strike price used elsewhere in the analysis. The red star (top right) marks the system-wide NetSEW maximum. The axes are truncated at the welfare-maximizing expansion levels.

The observed reduction in offshore wind investment as the generation CfD strike price increases from $1500$ to $2300$ can be directly explained by the sign and interpretation of the CfD$_{\text{gen}}$ term from the perspective of the governments. The expected CfD payment from the perspective of the governments, where a negative value indicates payment done to the OWF and vice versa is given by

$$\text{CfD}^{\text{gen}}_{\text{gov}} \sim -1 \cdot \sum_{r=1}^{8} \omega_r \left(\lambda^{\text{gen}}_{\text{CfD}} - \lambda_{x,r}\right) \Delta q_{x,\text{RES}}. \tag{5.4}$$

At low strike price levels, it holds in a large share of regimes that

$$\lambda^{\text{gen}}_{\text{CfD}} < \lambda_{x,r}, \tag{5.5}$$

which implies

$$\left(\lambda^{\text{gen}}_{\text{CfD}} - \lambda_{x,r}\right) < 0. \tag{5.6}$$

As a result, the CfD term is positive, indicating clawback payments from the OWF to the governments. These payments increase in magnitude with higher levels of wind expansion, assuming the self cannibalization effect does not push prices below the strike level:

$$\frac{\partial \text{CfD}^{\text{gen}}}{\partial \Delta q_{x,\text{RES}}} > 0. \tag{5.7}$$

Under the modeling assumptions, such payments are treated as funds entering/leaving the system, analogous to capital expenditure. As the strike price increases, the term

$$\left(\lambda^{\text{gen}}_{\text{CfD}} - \lambda_{x,r}\right) \tag{5.8}$$

becomes less negative and eventually positive in more regimes. Positive values correspond to , which are treated as funds entering the system. Therefore, at low strike prices, additional wind deployment increases the magnitude of clawback payments, while higher strike prices lead to more government support being paid out.

From a design perspective, the effectiveness of the cross-border generation CfD and the selection of an appropriate strike price are inherently dependent on prevailing market conditions according to the results from Figure 5.7 and Figure 5.8. For a given set of operational conditions (market condition expectations), a fixed strike price can lead to outcomes that are either beneficial or detrimental to one or both countries. As a result, under perfect information, countries adjust their investment decisions accordingly, opting for higher or lower levels of offshore wind deployment. For instance, around a strike price of $1900$, the expected payments to the OWF are close to zero. Beyond this point, the mechanism begins to shift from generating net clawbacks to requiring net support payments, altering the incentives for further wind expansion. Consequently, the choice of strike price plays a critical role in determining whether the CfD mechanism reinforces or weakens investment incentives (E-Bridge Consulting GmbH and Guidehouse, 2025), and its effectiveness cannot be decoupled from the underlying expectations on future market environment.

A further structural limitation of the cross-border $\text{CfD}_{\text{gen}}$ concerns the distribution of risk. While financial exposure under CfD mechanisms is common in domestic settings as well, the cross-border context introduces a qualitatively different dimension: the non-host country bears a share of this risk while retaining limited influence over the investment decisions and market conditions of the host country that ultimately determine the realized payouts.

## 5.4. Sharing radial costs under aggregated sharing keys

This section examines the implications of extending cost sharing to include radial connection infrastructure under aggregated benefit-based sharing keys. Building on the previous analysis of benefit-proportional allocation with cross-border $\text{CfD}_{\text{gen}}$, the comparison focuses on two settings: one in which only interconnection costs are shared, and one in which both interconnection and radial costs are included in the shared cost base. This setting allows for evaluating whether including additional cost components translates into improved coordination and investment outcomes in practice. The benefit-proportional allocation is selected here — rather than the equal split (50–50) used in preceding sections because it is expected under a BP key that broadening the cost scope is most consequential. As more cost components are brought into the shared base, the key re-calibrates to reflect the full distribution of realized benefits across both assets, making the quality of the allocation directly dependent on the comprehensiveness of the cost scope.

Figure 5.9 presents the expected system welfare surfaces and corresponding strategic equilibria for the two cost-sharing configurations under IC-only and IC+radial cost sharing. The resulting equilibrium outcomes and their welfare decomposition are reported in Table 5.9, while Table 5.10 summarizes the associated efficiency and distributional performance across the two settings.

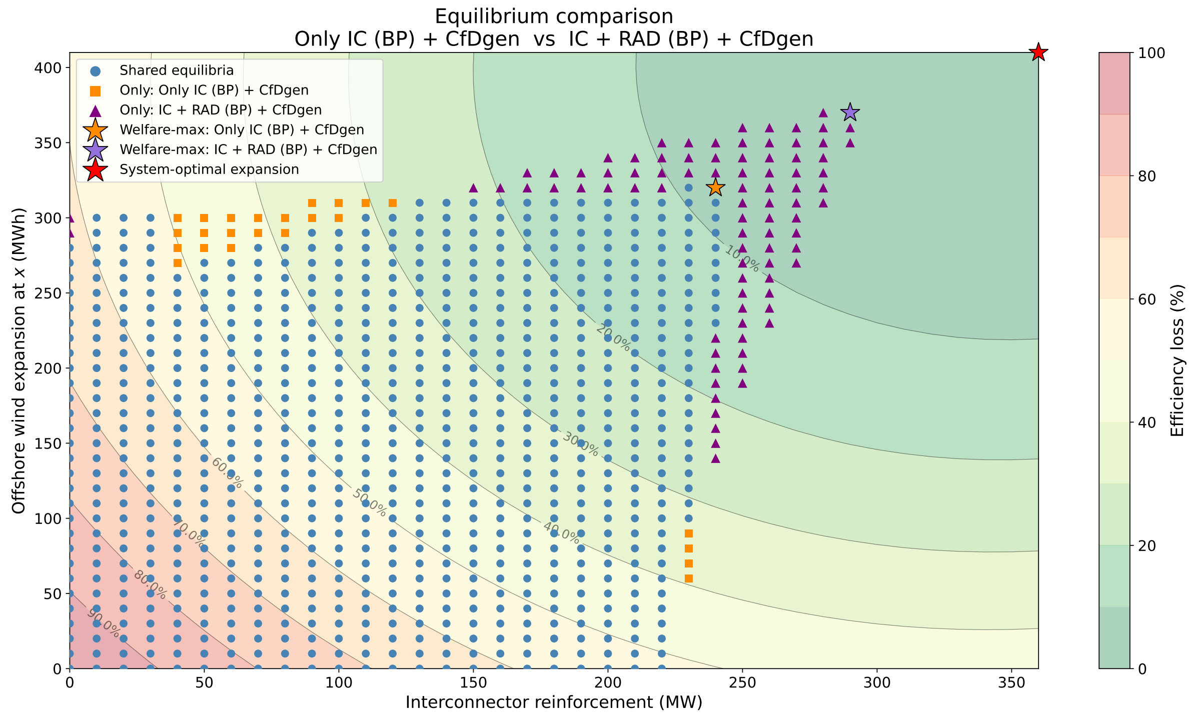



**Figure 5.9:** Strategic equilibria and efficiency loss landscape comparing benefit-proportional (BP) cost sharing with ex-post $\text{CfD}_{\text{gen}}$, under IC-only versus IC+radial cost scope. Background contours indicate efficiency loss relative to the system-optimal expansion (red star). Orange squares and purple triangles denote equilibria exclusive to each configuration respectively; blue circles are shared. Corresponding stars mark each mechanism's welfare-maximizing equilibrium. Figures are truncated at the welfare-maximizing expansion levels.

**Table 5.9:** Equilibrium outcomes and welfare decomposition by mechanism (BP; values in k€)

| Mechanism | $\Delta K$ | $\Delta q_{x,\text{RES}}$ | Country | $\Delta CS$ | $\Delta PS$ | $\Delta CR$ | CAPEX | $\Delta$CfD trans | $\Delta$CfD gen | $\alpha$ |
|---|---|---|---|---|---|---|---|---|---|---|
| Only IC (BP) + $\text{CfD}_{\text{gen}}$ | 240 | 320 | X | 630 | 228 | -52 | -506 | 0 | -11 | 0.433 |
| | | | Y | 127 | 223 | -72 | -34 | 0 | -15 | 0.567 |
| IC + RAD (BP) + $\text{CfD}_{\text{gen}}$ | 290 | 370 | X | 731 | 271 | -126 | -439 | 0 | -30 | 0.700 |
| | | | Y | 156 | 273 | -44 | -188 | 0 | -13 | 0.300 |

**Table 5.10:** Efficiency and distributional performance comparison (BP + $\text{CfD}_{\text{gen}}$: Only IC vs IC + RAD)

| **Mechanism** | **Efficiency Loss [%]** | **Mismatch [%]** |
|---|---|---|
| Only IC (BP) + $\text{CfD}_{\text{gen}}$ | 8.24% | 18.57% |
| IC + RAD (BP) + $\text{CfD}_{\text{gen}}$ | 2.43% | 0.55% |

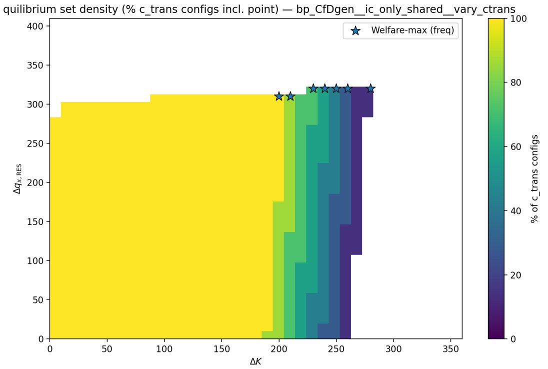
The results from Figure 5.9 indicate that extending cost sharing to include radial connections, in combination with a cross-border $\text{CfD}_{\text{gen}}$, yields more favorable outcomes than sharing only interconnection costs. The IC+radial setting supports a larger and more expansive negotiation space, with the welfare-maximizing equilibrium reaching $\Delta K = 290$ and $\Delta q_{x,\text{RES}} = 370$, compared to $\Delta K = 240$ and $\Delta q_{x,\text{RES}} = 320$ under IC-only sharing. This improvement is visible across both dimensions of the expansion space simultaneously, indicating that the inclusion of radial costs under the benefit-proportional key does not constrain but rather supports higher joint investment levels.

The performance comparison in Table 5.10 reinforces this finding. The IC+RAD configuration achieves an efficiency loss of only 2.43% and a cost-benefit mismatch of 0.55%, yielding an overall better performance than the IC-only setting, which records an efficiency loss of 8.24%, a mismatch of 18.57%. The inclusion of radial costs therefore improves outcomes on both efficiency and distributional alignment dimensions.

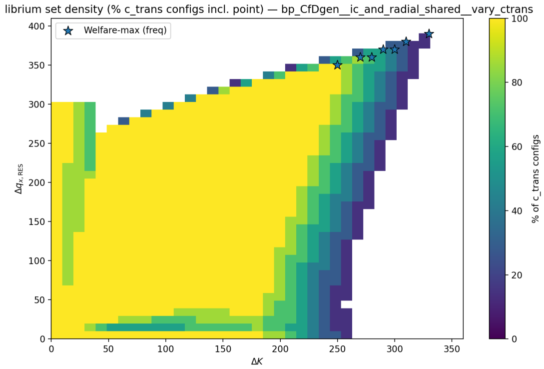
This shift is also reflected in the distributional outcomes reported in Table 5.9. Once radial connection costs are included in the sharing arrangement, the CAPEX borne by country $y$ increases markedly, rising from €34,007 in the IC-only setting to €188,058 when both interconnection and radial costs are shared. The benefit-proportional sharing keys adjust correspondingly, with country $x$'s share increasing from $\alpha_x = 0.433$ to $\alpha_x = 0.700$, while country $y$'s share decreases from $\alpha_y = 0.567$ to $\alpha_y = 0.300$. This reflects the fact that, under the aggregated benefit-proportional key, the inclusion of radial connection, which generates benefits disproportionately accruing to country $x$ as the host, shifts the cost burden accordingly. Despite the substantially higher CAPEX exposure for country $y$, the resulting allocation is sufficiently aligned with realized benefits that both countries find the expanded investment mutually acceptable, as evidenced by the near-zero mismatch. By increasing the scope of the costs considered under the BP setting, its accuracy was improved, which is how it was able perform the "best" overall among all tested mechanisms.

A further observation concerns the shape of the negotiation space across the two configurations. Under IC-only sharing, the feasible region is relatively rectangular and dense, with equilibria distributed uniformly across the space and a clean boundary cutting off at approximately $\Delta K = 240$ and $\Delta q_{x,\text{RES}} = 320$. When radial costs are included, the shape of the negotiation space shifts noticeably: rather than a clean rectangular boundary, the upper-right frontier follows a diagonal, meaning that the feasible space narrows as both dimensions increase simultaneously. At the extreme end, the highest achievable levels of interconnector expansion and offshore wind deployment are not simultaneously attainable — gaining more of one comes at the cost of accepting a lower level of the other along the frontier. Unsurprisingly, the best-case outcome is located at the very edge of this expanded negotiation space.

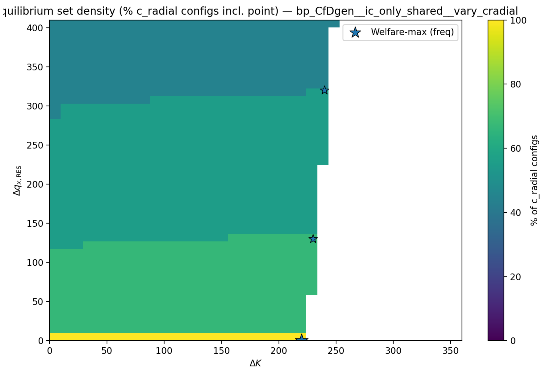
The cost sensitivity analysis in Figure 5.10 provides further insight into how cost composition affects benefit distribution under aggregated cost-sharing key settings.



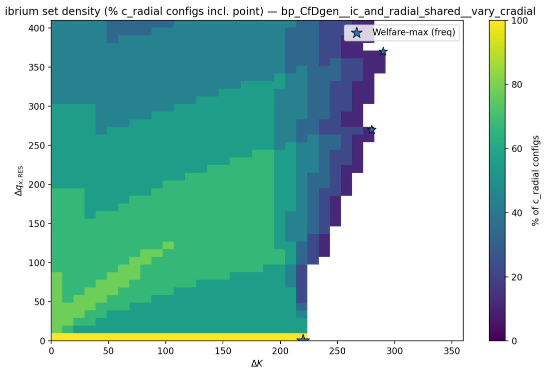

**(a)** IC-only shared — varying $c_{\text{trans}}$




**(b)** IC & radial shared — varying $c_{\text{trans}}$




**(c)** IC-only shared — varying $c_{\text{radial}}$




**(d)** IC & radial shared — varying $c_{\text{radial}}$

**Figure 5.10:** Cost sensitivity analysis for the BP + CfD$_{\text{gen}}$ mechanism. The top row shows variation in interconnector cost $c_{\text{trans}}$, while the bottom row shows variation in radial connection cost $c_{\text{radial}}$. The plotting region is fixed to the baseline system-optimal expansion. The figures are truncated at the welfare-maximizing expansion levels.

Turning to the cost sensitivity results in Figure 5.10, the sensitivity of equilibrium outcomes to cost parameters varies across the two settings in observable ways. Under IC-only sharing, varying $c_{\text{trans}}$ (panel a and b) produces a large and stable yellow region across low-to-mid expansion levels, with welfare-maximizing outcomes consistently supported in the upper portion of the feasible space. Increasing costs of the transmission asset shifts the negotiation space to the ”left”, to cover less area of interconnection expansion. On the other hand, variation of $c_{\text{radial}}$ (panel c vs d) causes a vertical shift in the negotiation space. Increasing the cost of the radial structure promotes the development of less offshore wind capacity, while reducing this cost component will lead to more investment in offshore wind (and indirectly more interconnector). Taken together, $c_{\text{trans}}$ governs the horizontal reach of the negotiation space while $c_{\text{radial}}$ governs its vertical extent, confirming that each cost parameter constrains investment along the dimension it directly finances.

Across all sensitivity analyses, the shape of the negotiation space remain intact. Since $c_{\text{trans}}$ is much lower than $c_{\text{radial}}$, varying it leads to less substantial impact on the available negotiation space with a majority of negotiation space remains intact across all runs (panels (a) and (b)). The same space is highly sensitive to changes in the unit cost of radial connection per MW (panels (c) and (d)). Consequently, cost components with larger magnitudes exert a disproportionate influence on equilibrium outcomes.

Finally, it is observed that regardless of whether the cost of radial infrastructure or interconnection is varied, the baseline system-optimal expansion point is no longer attainable (see Figure 5.10(b) and (d)). This is because the system-optimal solution itself is endogenous to the underlying cost parameters. Changes in asset-specific costs shift the relative net benefits of investment options, which alters the location of the welfare-maximizing outcome.

## 5.5. Combined effect of both types of ex-post instruments

This section examines the combined effect of introducing both ex-post instruments $\text{CfD}_{\text{trans}}$ and $\text{CfD}_{\text{gen}}$ on top of the equal (50–50) cost-sharing baseline, with only interconnector costs shared. The two mechanisms chosen for comparison represent opposite ends of the IC-only instrument spectrum: the simplest configuration considered in this study (Only IC, 50–50) and the most instrument-rich IC-only setting (Only IC, 50–50 + CfDtrans + CfDgen). By comparing these directly, the analysis isolates the aggregate impact of combining both ex-post tools without expanding the scope of cost-sharing to include radial infrastructure.

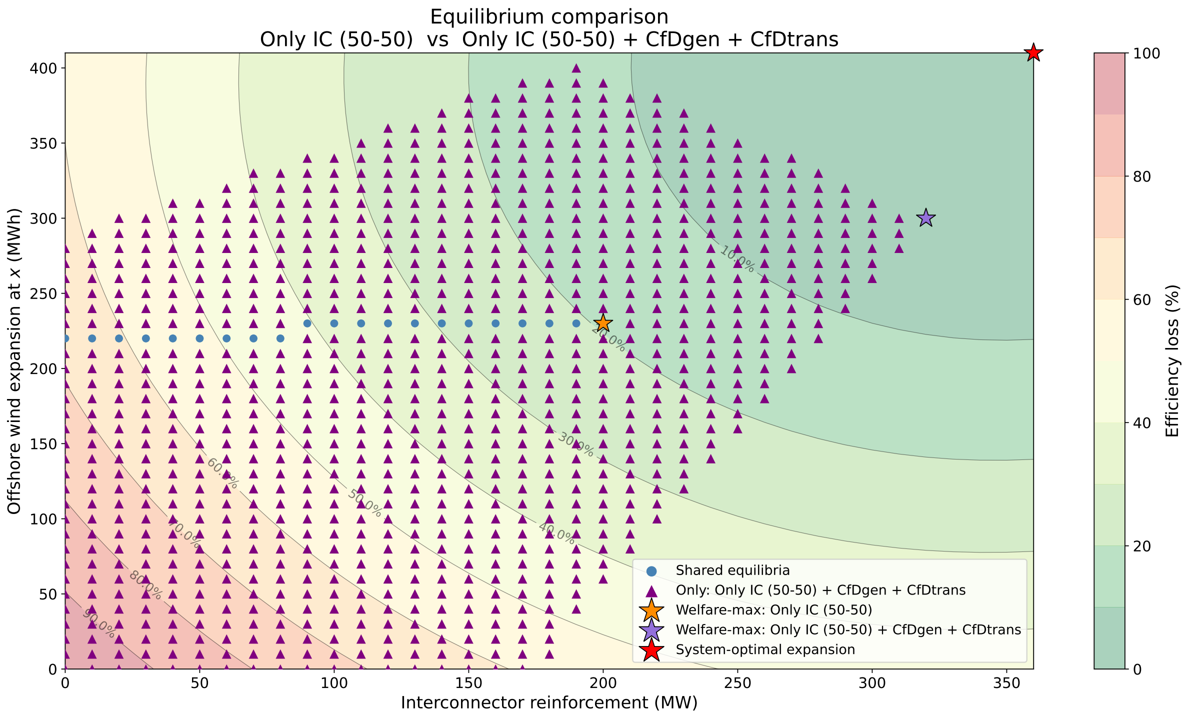



**Figure 5.11:** Strategic equilibria and efficiency loss landscape comparing the ex-ante-only IC (50–50) mechanism against the same allocation supplemented by both ex-post instruments $\text{CfD}_{\text{trans}}$ and $\text{CfD}_{\text{gen}}$. Background contours indicate efficiency loss relative to the system-optimal expansion (red star). Purple triangles denote equilibria exclusive to the combined instrument setting; blue circles are shared. Corresponding stars mark each mechanism's welfare-maximizing equilibrium. Figures are truncated at the welfare-maximizing expansion levels.

**Table 5.11:** Equilibrium outcomes and welfare decomposition by mechanism (50–50; values in k€)

| Mechanism | $\Delta K$ | $\Delta q_{x,\text{RES}}$ | Country | $\Delta CS$ | $\Delta PS$ | $\Delta CR$ | CAPEX | ΔCfD trans | ΔCfD gen | $\alpha$ |
|---|---|---|---|---|---|---|---|---|---|---|
| Only IC (50–50) | 200 | 230 | X | 432 | 221 | -49 | -370 | 0 | -3 | 0.500 |
| | | | Y | 93 | 193 | -49 | -25 | 0 | 0 | 0.500 |
| Only IC (50–50) + $\text{CfD}_{\text{gen}}$ + $\text{CfD}_{\text{trans}}$ | 320 | 300 | X | 265 | 290 | -106 | -280 | 64 | -9 | 0.500 |
| | | | Y | 148 | 322 | -106 | -40 | -64 | -9 | 0.500 |

When ex-post adjustment mechanisms $\text{CfD}_{\text{trans}}$ and $\text{CfD}_{\text{gen}}$ are introduced, the feasible set

**Table 5.12:** Efficiency and distributional performance comparison (50–50: Only IC vs IC + RAD + $\mathrm{CfD}_{\mathrm{trans}}$ + $\mathrm{CfD}_{\mathrm{gen}}$)

| Mechanism | Efficiency Loss [%] | Mismatch [%] |
|---|---|---|
| IC + RAD (50–50) + $\mathrm{CfD}_{\mathrm{gen}}$ + $\mathrm{CfD}_{\mathrm{trans}}$ | 3.83% | 17.58% |
| Only IC (50–50) | 19.35% | 19.60% |

of mutually acceptable expansions expands considerably. Instead of a narrow, line-like structure (as observed under the default 50-50 split with interconnector only setting), a broad area of feasible agreements emerges. The resulting equilibrium expansion is substantially closer to the system-optimal solution.

A closer comparison with the $\mathrm{CfD}_{\mathrm{trans}}$-only results from section 5.2 reveals a notable trade-off. When only $\mathrm{CfD}_{\mathrm{trans}}$ is applied, the best-case equilibrium reaches $K = 350$ MW and $\Delta q_{x,\mathrm{RES}} = 360$ MWh. The introduction of CfDgen alongside CfDtrans shifts the equilibrium to $K = 320$ MW and $\Delta q_{x,\mathrm{RES}} = 300$ MWh. In other words, adding CfDgen does not further increase the investment level achieved at equilibrium — it actually reduces it relative to the $\mathrm{CfD}_{\mathrm{trans}}$-only setting. The primary effect of combining both instruments is therefore not a higher agreed investment point, but rather the expansion of the negotiation space from a narrow line into a broad feasible region, as visible in Figure 5.11.

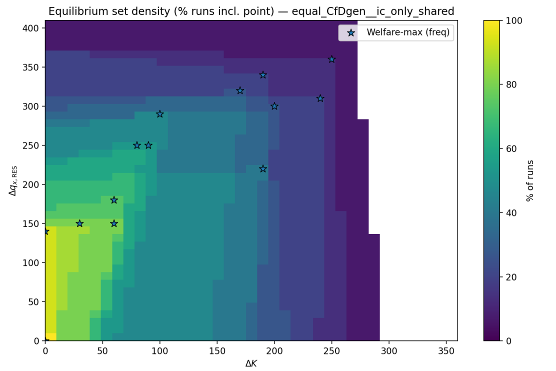
Additionally, the welfare decomposition in Table 5.11 shows that the two instruments operate on fundamentally different logics. $\mathrm{CfD}_{\mathrm{trans}}$ functions as a bilateral transfer between countries, flowing from $y$ to $x$ (€ +64,446 for $x$, € $-64{,}446$ for $y$). $\mathrm{CfD}_{\mathrm{gen}}$, by contrast, is not an inter-country transfer — both countries record an identical outward payment of € $-9{,}251$ as a joint contribution to the OWF as an external party. The two instruments therefore do not offset each other distributionally between $x$ and $y$. Rather, their combination layers a bilateral redistribution mechanism on top of a joint outward subsidy: $\mathrm{CfD}_{\mathrm{trans}}$ reshapes the balance between the two countries, while $\mathrm{CfD}_{\mathrm{gen}}$ simultaneously draws resources from both toward the offshore wind farm.

## 5.6. Structural properties of the negotiation space across mechanisms

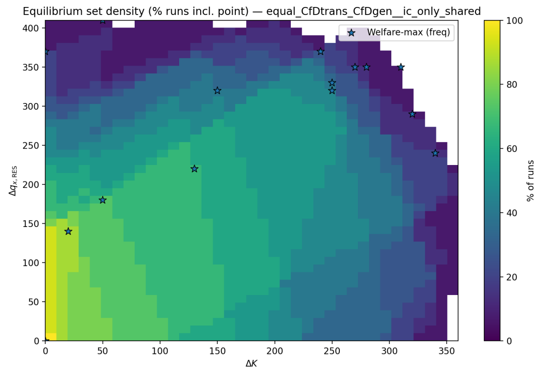
Across all configurations in which both interconnector and wind investment costs are shared, an equilibrium line emerges along the $\Delta K$ axis (the horizontal axis), most visibly in Figure 5.9 and Figure 5.11. This line consists of multiple Nash equilibrium points at which both countries agree on the expansion outcome. The presence of this line is noteworthy because it represents a clear transition from the remainder of the expansion options. Along this line, no additional offshore wind capacity is deployed ($\Delta q_{x,\mathrm{RES}} = 0$), meaning that countries agree exclusively on expanding interconnector capacity. Consequently, although the underlying cost-sharing configuration allows for the joint sharing of both wind and interconnector investment costs, the problem effectively reduces to an interconnector-only expansion setting along this line. Interestingly, this interconnector-only expansion path consistently results in larger interconnector capacity expansions than expansion points where offshore wind capacity is also increased within the same cost-sharing mechanism. In other words, when no additional wind is deployed, countries tend to agree on higher levels of interconnection capacity.

When the ex-post instruments are introduced, a dense equilibrium region emerges across a large portion of the expansion space as can be seen in Figure 5.12.

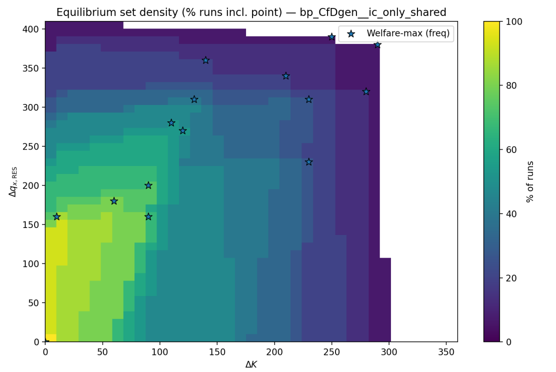
This indicates that although some expansion options remain sensitive to specific expectations about future market conditions, there also exist regions that are consistently supported across weight configurations. Combining ex-ante equal sharing with both ex-post correction tools produces a mechanism whose equilibrium region remains relatively sta-



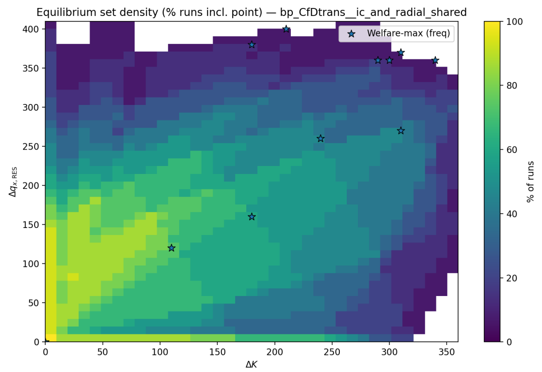

**(a)** (50–50) + CfD$_{\text{gen}}$ (IC-only)




**(b)** (50–50) + CfD$_{\text{trans}}$ + CfD$_{\text{gen}}$ (IC-only)




**(c)** BP + CfD$_{\text{gen}}$ (IC-only)




**(d)** BP + CfD$_{\text{trans}}$ (IC & radial shared)

**Figure 5.12:** Equilibrium set density across mechanisms with CfD instruments. The top row shows Equal-based mechanisms, while the bottom row presents BP-based mechanisms. Colors indicate the share of runs supporting each equilibrium, and markers denote welfare-maximizing outcomes. The figures are truncated at the welfare-maximizing expansion levels.

ble across the weight configurations tested. In addition, the resulting stable negotiation region appears relatively continuous rather than fragmented into isolated islands. This characteristic may make the mechanism more attractive from a governance perspective, as it leaves room for negotiation while maintaining stability in cooperative outcomes.

Another observation concerns the origin of the expansion grid. Across all cost settings in which both interconnector and wind investment costs are shared, the origin $(\Delta K = 0, \Delta q_{x,\text{RES}} = 0)$ lies within the feasible negotiation space. At this point, where no expansion occurs, neither country experiences a change in welfare relative to the baseline. Consequently, both countries are indifferent to the investment decision, making the absence of expansion an acceptable outcome.

This observation highlights that, under the static conditions considered in the model, countries may rationally choose not to invest at all. Although it has already been established that no point in the negotiation space represents a guaranteed investment outcome, it is also important to emphasize that the cost-sharing mechanisms themselves do not inherently ensure that investment will occur. In particular, in settings where both wind and interconnector costs are shared, it remains possible for one of the countries to block expansion entirely, effectively reverting the outcome to the status quo in which only existing infrastructure remains in place.

In this case, the expansion of offshore wind located in country $x$ would lie entirely within $x$'s own investment preferences. Consequently, wind investment would no longer require cross-border agreement, effectively reducing the negotiation problem to one in which only interconnector costs are shared between the countries. If country $x$ is willing to finance additional offshore wind capacity unilaterally, the joint bargaining problem over wind investment effectively disappears. In that case, the both-costs-shared setting collapses, from a strategic perspective, to a problem in which only interconnector expansion remains subject to cross-border agreement. However, this does not imply that the resulting problem is equivalent to the original interconnector-only cost-sharing setting. Unilateral wind expansion by $x$ alters market prices, congestion patterns, and the marginal benefits of interconnector reinforcement for both countries. As a result, the negotiation problem may revert institutionally to interconnector-only cost-sharing, but under a different economic environment shaped by the new level of offshore wind deployment.

## 5.7. Overall performance across weight sensitivities

The preceding sections examined how the agreed equilibrium relocates across the parameter space as the objective weights are varied. This section shifts the focus from *where* the equilibrium settles to *how well* it performs, summarized through the two indicators carried throughout the analysis: the efficiency loss and the cost–benefit mismatch. Each weight configuration produces one value of each indicator for every mechanism, and the two figures below summarize that collection from complementary angles: Figure 5.13 considers the indicators one at a time, while Figure 5.14 sets them against each other.

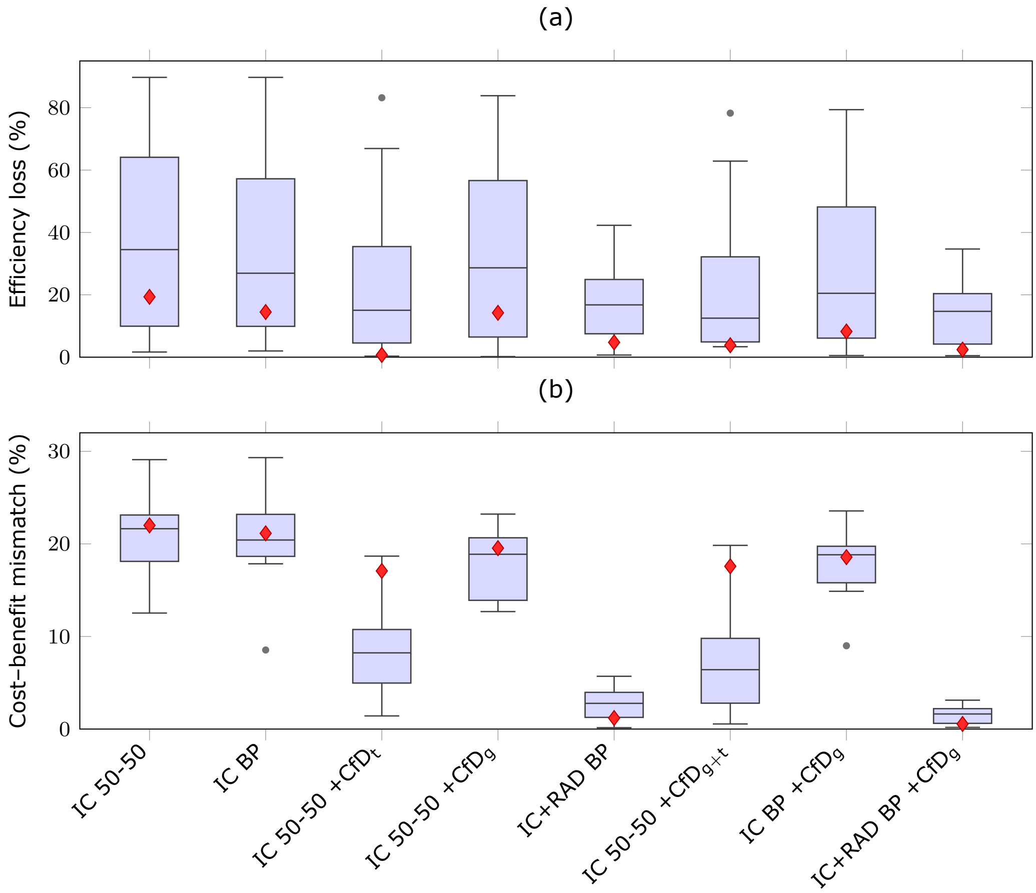



**Figure 5.13:** Dispersion of the two performance indicators across the weight-sensitivity runs, by cost-allocation mechanism. Each box summarizes one mechanism's distribution over the runs (median line, interquartile range, whiskers; dots are outliers), and the red diamonds mark the baseline configuration. Panel (a) reports efficiency loss relative to the welfare-maximizing point; panel (b) reports the cost–benefit mismatch. Whereas the equilibrium-location maps in previous sections show *where* the agreed equilibrium relocates under the same variation, this figure shows how the resulting *outcome quality* responds.

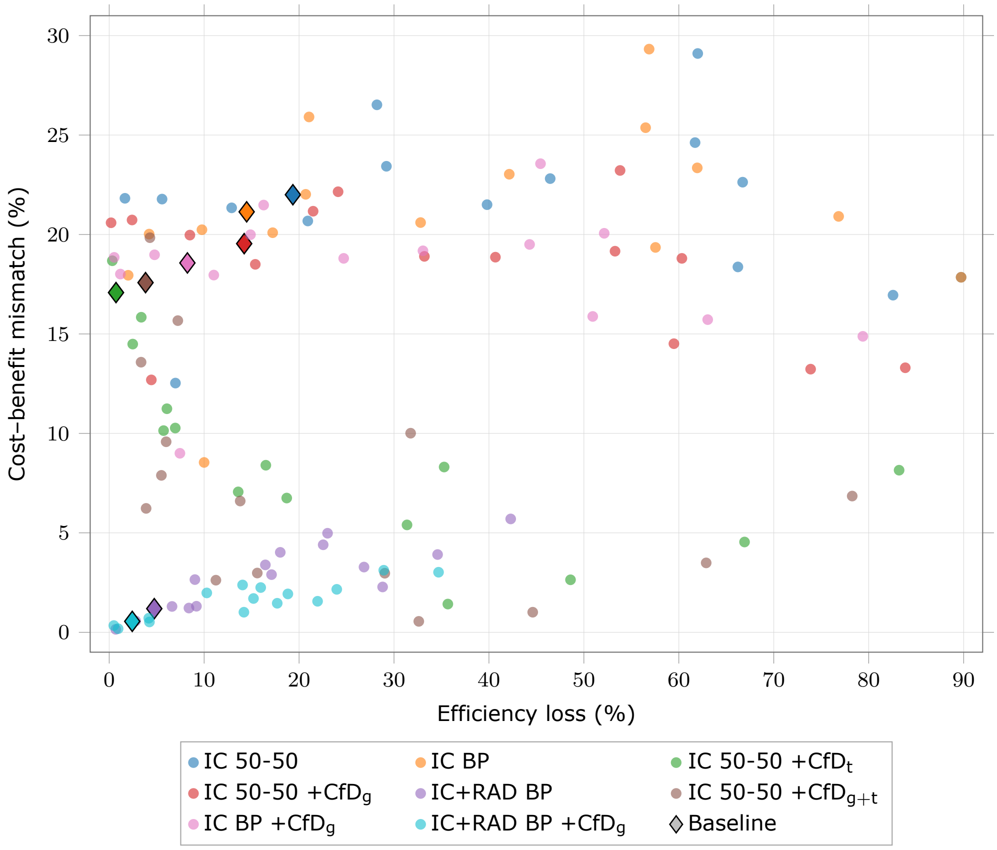



**Figure 5.14:** Joint behaviour of the two performance indicators across the weight-sensitivity runs. Each point is one (mechanism, run) pair, coloured by cost-allocation mechanism; the enlarged black-edged diamonds mark each mechanism's baseline configuration. The horizontal axis is efficiency loss and the vertical axis is the cost–benefit mismatch, so points nearer the origin are jointly more favourable. The extent of each colour cloud indicates that mechanism's sensitivity to the objective weights. Whereas the equilibrium-location maps in previous sections show *where* the agreed equilibrium relocates under the same variation, this figure shows the resulting efficiency–mismatch position.

# 5.8. Synthesis of mechanism cases and lessons learned

This section synthesizes the cross-cutting insights that emerge from the mechanism comparisons in the preceding sections. Rather than restating individual results, it identifies the broader patterns in how the design and combination of ex-ante and ex-post instruments shape investment incentives, distributional outcomes, and the scope for cross-border cooperation.

## 5.8.1. Coordination and benefit-aligned cost-sharing are key to unlocking efficient offshore wind and interconnection expansion

Mechanisms that align cost contributions more closely with realized benefits generally produce agreed expansions closer to the system optimum, indicating that benefit-aligned cost-sharing can reduce (though not eliminate) the investment disincentives created by cross-border benefit spillovers. This is in line with Willems et al. (2025), who frame this *coordination problem* as the cost–benefit asymmetry arising from a suboptimal allocation of investment costs, which drives countries toward a unilateral focus on national welfare and, in turn, an inefficient use of North Sea offshore wind potential. The results of section 5.1 further show that agreeing to expand interconnector capacity yields a more system-optimal outcome than a unilateral offshore wind approach with no additional cross-border transmission, and that, although not guaranteed, greater interconnection can itself incentivize the host country to invest more in offshore wind. This is supported by European

Commission (2024), which notes that cross-border electricity trade via onshore interconnectors is critical to ensuring Member States are willing to host offshore projects, and that simple keys such as the equal (50–50) split prove less effective than proportional-to-benefits allocation.

### 5.8.2. CfD for transmission enhances expansion but may face practical limits due to high, uncertain transfers and calibration sensitivity

The $\text{CfD}_{\text{trans}}$ drives higher wind and interconnection investment than the ex-ante-only setting, as the non-host country compensates the host for the benefits it gains from improved access to zero-marginal-cost energy. However, the scale of this compensation is large: of country $y$'s total expenditure, roughly 67% takes the form of an ex-post payment it would not know prior to the realization of the project.[2] Kristiansen et al. (2018), from which the $\text{CfD}_{\text{trans}}$ is derived, similarly note that compensation levels in their model can reach extremes. This raises concerns regarding the practical feasibility of the instrument, as countries may be unwilling to expose themselves to such large and uncertain ex-post obligations; investments may not materialize if the balance of known versus unknown costs lies beyond investors' risk tolerance. While the optimal strike price was not explicitly modeled, the results of section 5.2 confirm the corrective functionality of the mechanism, but also show — via the sensitivity analysis — that the strike price is decisive for its effectiveness. The instrument is therefore not plug-and-play: it operates as intended only under the market conditions for which its strike price is calibrated, and is best understood as a tool to correct a known misalignment between an initial allocation and one that more closely reflects costs proportional to net benefits, such as a Shapley value (SV)-based allocation as suggested by Willems et al. (2025). Even with an optimal strike price, the sensitivity of the mechanism to varying market expectations presents a challenge to its practical applicability.

### 5.8.3. Broader cost scope can improve outcomes under BP allocation

European Commission (2024) suggests including radial connections and onshore grid reinforcements in cross-border cost-sharing exercises, provided they demonstrate clear cross-border relevance. The results of section 5.4 show that including radial connection costs can lead to more favorable outcomes when generation and transmission costs are allocated under a single aggregated, benefit-proportional key. The central insight is that a broader scope need not reduce flexibility in reaching mutually beneficial agreements: under a benefit-proportional key, the key self-adjusts to reflect the full benefit asymmetry introduced by the additional cost component, so scope expansion can improve rather than distort distributional alignment. The impact of including additional cost components is thus determined not by the width of the cost base alone, but by the interaction between that cost base and the sharing rule applied to it — a rule that re-calibrates with scope can absorb new components in a distributionally coherent way, whereas one that does not will amplify asymmetries. As noted by Willems et al. (2025), however, the strong interdependencies between assets make it inherently difficult to isolate and assign benefits to individual components, so the quality of the benefit attribution underlying the key remains a binding constraint on how well this self-adjustment functions in practice.

### 5.8.4. Combining instruments does not necessarily improve investment outcomes

Combining both ex-post instruments does not monotonically increase the agreed investment level relative to using $\text{CfD}_{\text{trans}}$ alone; the best-case equilibrium under the combined mechanism is lower on both dimensions. The two instruments therefore do not simply reinforce one another in pushing investment toward the system optimum, but their in-

[2]The focus here is on the share of ex-ante versus ex-post costs rather than the represented absolute figures.

teraction reshapes the strategic incentive structure, shifting rather than extending the location of the agreed outcome. Whether this directional effect generalizes beyond the present parameterization cannot be established from this analysis alone, but it cautions against assuming that layering instruments always improves performance. This is consistent with the earlier observations that the $\text{CfD}_{\text{trans}}$ must be calibrated precisely to the underlying market and cost setting (subsection 5.8.2) and that broadening the cost scope works well only when the sharing keys are able to self-adjust to that expansion (subsection 5.8.3). Taken together, combining instruments can work, but only if the underlying cost-sharing mechanism is re-calibrated accordingly. Finally, Offshore TSO Collaboration (OTC) (2025) notes that cost-sharing arrangements must adhere to unbundling rules requiring the separate financing of generation and transmission to avoid cross-subsidization, so combining the two mechanisms under a single aggregated scheme may not be feasible under current regulations.

### 5.8.5. Mechanism performance depends on alignment of expectations

The weight-based sensitivity analyses conducted across all mechanisms reveal a consistent structural finding: no mechanism evaluated in this study produces equilibrium outcomes that are stable across changes in countries' expectations about future market conditions, though the degree of sensitivity varies across mechanisms. Ex-ante-only settings yield narrow and fragmented equilibrium regions, whereas ex-post instruments that allow offshore wind costs to be shared — particularly $\text{CfD}_{\text{gen}}$ and the combined $\text{CfD}_{\text{trans}} + \text{CfD}_{\text{gen}}$ setting — produce denser and more continuous feasible regions. Ex-post instruments thus reduce the sensitivity of the *existence* of an agreement to market expectations; yet even within these broader regions, the investment levels closest to the welfare-maximizing outcome remain supported in only a minority of runs across all mechanisms. The consistency of high-investment outcomes therefore remains limited regardless of instrument configuration. The implication is that mechanism design alone may be insufficient to guarantee high-investment outcomes: a shared forecasting framework or agreed scenario structure between countries would be a necessary complement, whichever financial instrument is chosen. This is consistent with how the challenge is framed in practice. ACER – European Union Agency for the Cooperation of Energy Regulators (2023) explicitly states that benefit results depend significantly on input scenarios and related assumptions, and recommends that NRAs agree on how to account for each robust and plausible scenario before taking cross-border cost-allocation decisions. Similarly, OTC (2025a) identifies joint scenario development as a foundational step in collaborative offshore grid planning, noting that scenario building is the starting point of all further planning. The sensitivity of equilibrium outcomes to regime weights observed across all mechanisms can therefore be read as a model-level reflection of a real governance challenge: without a shared basis for assessing future market conditions, the stability of any cost-sharing agreement, regardless of its financial structure, remains inherently fragile.

### 5.8.6. Connection to results-based follow-up discussion

The findings presented in this chapter should be interpreted as model-based results within the stylized two-country framework. They show how different cost-sharing mechanisms affect equilibrium investment outcomes, welfare distribution, and negotiation space under the assumed parameterization and sensitivity ranges, and the preceding cross-cutting insights (section 5.8) draw these results together into a set of broader patterns spanning the mechanisms examined. The following discussion builds on these insights to translate the model results into broader implementation and policy implications.

# 6

# Discussion

This chapter interprets the model results presented in Chapter 5 and examines their implications beyond the analytical boundaries of the stylized framework. Building on the cross-cutting insights drawn together at the end of Chapter 5, Section 6.1 translates these insights into practical implementation considerations, while Section 6.2 discusses broader governance and policy implications for regional cooperation in the North Sea. These sections should be understood as interpretations informed by the model results, stakeholder discussions, and available literature, rather than as direct outputs of the quantitative model. The scope and focus of the discussion were informed by consultations with industry stakeholders, whose questions and pointers helped identify the most policy-relevant dimensions to examine; though all conclusions remain grounded in the model results and available literature.

## 6.1. Implementation considerations

The cross-cutting insights in section 5.8 establish what the mechanisms can and cannot achieve under idealized analytical conditions. The considerations in this section are not direct outputs of the model. Rather, they translate the model results into practical design questions that would arise if the evaluated mechanisms were to be considered in real-world cross-border negotiations.

Four implementation dimensions are considered: the design and operational use of the transmission CfD, the incidence of costs across payers, bargaining asymmetries and strategic behavior between participating countries, and the implications of different offshore wind farm asset configurations.

### 6.1.1. Transmission CfD - design and use

The model results indicated the high effectiveness of the $CfD_{trans}$, but further analysis in subsection 5.8.2 highlighted the worsening effects of incorrect strike calibration. Overall, the results indicate that it can be a useful tool to enable high volumes of investment under the right conditions. Some practical considerations that would enable an effective use of this tool:

- Calibration circularity and threshold: The strike price should be set to correct toward a target allocation such as the SV as suggested by Willems et al. (2025) and demonstrated by Kristiansen et al. (2018), or a point higher-up on the expansion grid as was demonstrated in the present model. This target allocation itself depends on realized benefits, which depend on the strike price. This requires agreed ex-ante benefit forecasts to anchor calibration. One way this can be done is through a predefined divergence threshold: when the difference between the initially allocated and realized net-benefits exceeds this threshold, it signals the need for strike price recalibration. This links the $\text{CfD}_{\text{trans}}$ design directly to the periodic revision cycle discussed above, ensuring that the corrective instrument remains aligned with evolving market conditions rather than drifting from its intended allocation target.

- Correction cap: In order to limit the scale of exposure, or limit the amount of unknown costs prior to FID, a budgetary cap on the amount of ex-post $\text{CfD}_{\text{trans}}$ can be set. This term can either be an absolute value budgeted prior to FID, or in terms of percentage of total costs throughout the lifespan of the asset(s) or one assessment cycle. The assessment cycle could be the parallel to the 2-year TYNDP revision by ENTSO-E, or span across a longer period as was suggested by European Commission (2025d). This approach could better cover the flexibility needs while ensuring a degree of investment certainty, which appears to be a key trade-off with the use of ex-post tools according to Offshore TSO Collaboration (OTC) (2025).

Figure 6.1 provides this cyclic process. When the divergence of the accrued net-benefits per country against the initial agreed-upon forecasts are larger than the threshold, the CfD for transmission is activated. Until the next time for assessment, Until a correction cap, in place to improve investment certainty, is reached- the CfD would accumulate transfers based on flows and price differences, for which the strike price was calibrated. The cycle can repeat as long as there is a big enough deviation from initial expectations.

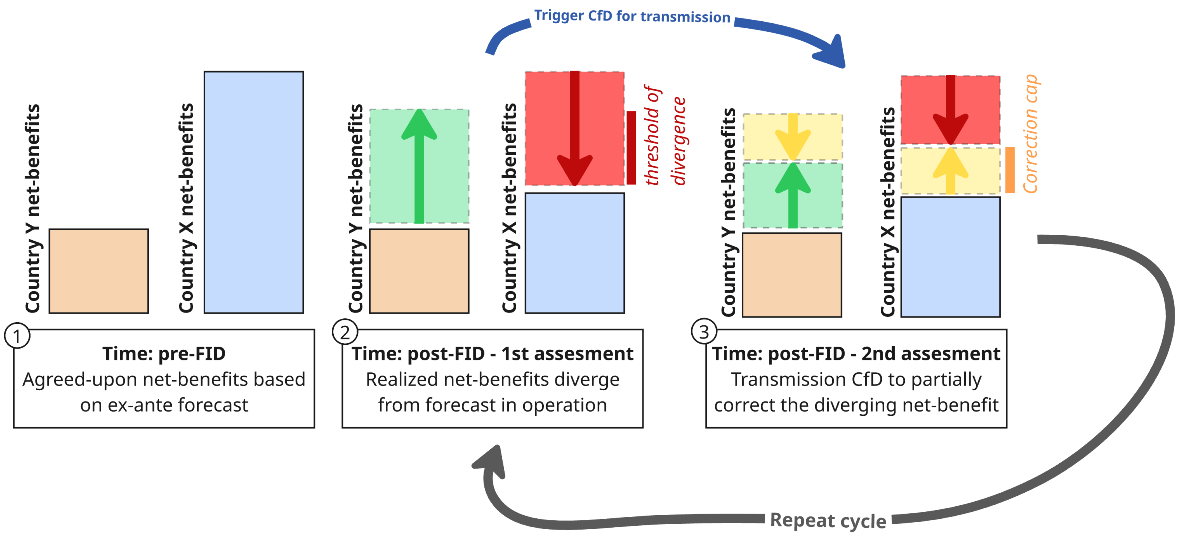



**Figure 6.1:** Proposed operational cycle of the $\text{CfD}_{\text{trans}}$: ex-ante allocation (1), divergence assessment against threshold (2), and partial ex-post correction subject to a correction cap (3), repeated across assessment periods

Introducing caps on correction transfers — whether by volume or proportion — restores cost predictability for participating countries, but at the cost of limiting the corrective reach of the instrument. As the model results illustrate, the uncapped case already exposes $y$ to approximately 70% of total costs through the ex-post transfer, a level that may exceed political risk tolerance. The design therefore involves a fundamental trade-off: tighter caps improve ex-ante cost certainty but reduce the mechanism's ability to correct the very misalignment it was designed to address. Finally, there is uncertainty involving the owners of such a contract. From a legal and regulatory perspective, more clarity is needed as to how $\text{CfD}_{\text{trans}}$ would be treated- how does the transaction flow, is it a tariff component, how is it included in the TSO's RAB?

It is also important to mention that Kristiansen et al. (2018) explicitly states that their $\text{CfD}_{\text{trans}}$ is only one mechanical formulation to correct an ex-ante allocation. Although this study only considered this type of CfD, there may be other contractual tools that fulfill the same functionality, perhaps even more aligned with the practical considerations presented here. The OTC is developing their own cost-sharing methodologies that utilize similar governance criteria. It is worth noting that the OTC-NSEC workshop on the 26th of March, 2026, in Brussels served as an inspiration to come up with these suggestions, which are adapted to work with the considered $\text{CfD}_{\text{trans}}$.

### 6.1.2. Who ends up paying?

The model operates at the country-surplus level and does not capture how costs pass through to final payers. Whether consumers (via network tariffs), taxpayers (via government budgets and levies) (Heussaff, Jüngling, Tagliapietra, and Zachmann, 2025), or investors (via reduced returns). Still, the incidence chain can be traced for each mechanism as shown in Table 6.1.

**Table 6.1:** Incidence and pass-through structure of cost-sharing mechanisms

| Mechanism | First-order payer | Pass-through channel | Final payer | Model result | Validation source |
|---|---|---|---|---|---|
| Ex-ante cost allocation | TSO of each country, proportional to agreed sharing key | Added to regulatory asset base (RAB); recovered via network access tariffs | Electricity consumers in each country | Both $x$ and $y$ bear CAPEX proportional to $\alpha$ (model results, Table 5.7) | (ACER – European Union Agency for the Cooperation of Energy Regulators, 2023) & (Heussaff and Zachmann, 2025) |
| $\text{CfD}_{\text{trans}}$ | TSO of $y$, via ex-post settlement* | Absorbed into $y$'s tariff base; recovered via network charges to $y$'s consumers** | $y$'s electricity consumers — despite receiving the offsetting benefit of cheaper imports | $y$'s ex-post obligations in the uncapped parameterization (model results, Table 5.4) | (Heussaff and Zachmann, 2025)*** |
| $\text{CfD}_{\text{gen}}$ | Government(s) of $x$ and $y$, acting as joint counterparty to the OWF | Recovered via a levy on electricity consumers or a direct budget line; funding source not yet defined for cross-border case | Electricity consumers in both $x$ and $y$; or taxpayers if budget-financed | Both countries record equal outward payments in the parameterized case, regardless of which country hosts the wind (model results, Table 5.7) | (Weckenbrock and Boirot, 2025) & (European Commission, 2022) |

*Notes:*
* Assuming $y$ is compensating $x$.
** The exact structure of this is still an open question (see subsection 6.1.1).
*** Limitation: currently no source to directly validate how such contracts would be utilized, but the logic is sound: TSO $\rightarrow$ tariff $\rightarrow$ consumer.

The host country $x$'s consumers already benefit from cheaper wholesale prices with more wind, so the consequent $\text{CfD}_{\text{gen}}$ levy falls on them in addition to whatever support costs already exist for domestic wind[1]. For $y$'s consumers, the levy funds wind in a foreign country and the benefit (price reduction via cheaper imports) is indirect and uncertain. The model cannot capture this level of detail, so the political economy challenge remains unresolved. Across all mechanisms, costs ultimately flow through to electricity consumers. Producers benefit across all configurations where they gain from increased market coupling without bearing investment costs. The TSO absorbs both CAPEX obligations and additional $\text{CfD}_{\text{trans}}$ settlement exposure, which under standard regulatory cost recovery are passed through to network users via tariffs (Heussaff and Zachmann, 2025). The consumer is therefore the residual bearer of costs under all configurations.

The injection charge proposed by TenneT TSO B.V. (2025) can see some of this burden be shifted from consumers (regardless of which country) to producers as well. However, their applicability both domestic and cross-border is an open question.

### 6.1.3. Bargaining asymmetries and strategic behavior

Present model implicitly assumes symmetric Nash bargaining, where both countries are equally capable of vetoing. In retrospect, Kristiansen et al. (2018) presented results of a simulation environment that endogenously considered bargaining power for transmission projects. They conclude that the host country has strong bargaining power and will only participate if it receives a sufficiently large share of net benefits; on top of that, they criticize the 50-50 split and benefit-proportional[2] ex-ante rules because they do not consider the host country's veto-power, which is likely to become an even more profound issue

[1] In the model, no past CfD has been implemented for existing wind capacity prior to expansion.
[2] Kristiansen et al. (2018) uses instead the positive-net-benefit-differential (PNBD) principle which is methodologically synergetic to the benefit-proportional allocation.

when the cost-sharing scope is expanded to a multilateral setting (e.g. the greater North Sea). These effects were not directly captured through the model results but are recognized as valid concerns. Multiple practical constraints arise that will affect each nation's bargaining power:

- Host country informational advantage: Under real-world settings, the host country will likely have more complete information of actual construction costs, grid operation details, and domestic market dynamics compared to the non-host country. This informational asymmetry may allow the host country to strategically misrepresent costs or downplay cross-border benefits during negotiations in order to bias the sharing key in its favor. This concern is supported by Damoun and Poudineh (2025), who show that a party with superior information can misrepresent its costs to shift the distribution of gains in its favor, at the expense of overall welfare. In a broader context, bargaining outcomes are shaped not only by the expected gains from the investment, but also by the underlying information structure (Skrzypacz, 2004).
- Gaming effects via own RES investment: As made clear in subsection 6.1.1, the $\text{CfD}_{\text{trans}}$ operates effectively only under well-calibrated conditions. Since payment obligations are determined by cross-border flows and reference wholesale prices, either party may have incentives to game the mechanism. For instance, the non-host country ($y$) could invest in domestic RES and/or storage to narrow inter-zonal price spreads, or conversely dis-invest in existing capacity to reduce price convergence and limit its $\text{CfD}_{\text{trans}}$ payment exposure. Similarly, if $x$ is aware of $y$'s investment trajectory, it may time its offshore wind expansion strategically to maximize cross-border price differentials and, with it, the transfer it receives from $y$. Relevantly, Willems et al. (2025) discuss that a country's reliance on imported wind energy, and therefore the benefits it receives from an interconnector, can change over time as its energy mix evolves- which may see them withdraw from cost contributions. They frame this as a hold-up problem and argue that well-designed agreements should hedge against such shifts in national energy policy.
- Fallback and temporal dependency: Model results show the asymmetric fallback positions in section 5.1, where $x$ can choose to invest unilaterally if no cost-sharing agreement is made but $y$'s fallback is the status quo. In reality, however, both countries can choose to continue (or not) investing in offshore wind on their own. When this happens, future cost-sharing negotiations may see that cross-border benefits have become difficult to justify due to the temporal dependency of benefits reaped from individual assets. Ultimately, if high expansion levels are achievable only under strategic cross-border cooperation, they may be rendered unachievable if countries first satisfy their own national agenda without considering a collective goal.

To address these challenges, transparency is essential — both in the assumptions underlying the cost-sharing methodology (Offshore TSO Collaboration (OTC), 2025) and in the operational parameters relevant after FID. Initially, these novel cross-border agreements should involve countries that already share a long-standing mutual understanding of ambitions, governance, and operations. Such familiarity can provide a foundation of trust that helps mitigate these risks, given that cost-sharing mechanisms do not eliminate them structurally.

## 6.2. Leveling up regional cooperation

As highlighted in the problem background and reflected in the results of the analysis, the lack of coordination leads to suboptimal expansion of offshore wind and interconnection capacity in the North Sea. The modeling exercise demonstrates that investment outcomes vary depending on both the degree and the design of coordination mechanisms. Figure 6.2 illustrates the different levels of cooperation within the bilateral investment setting, encompassing both elements directly captured by the model and additional aspects identified through the broader contextual analysis.

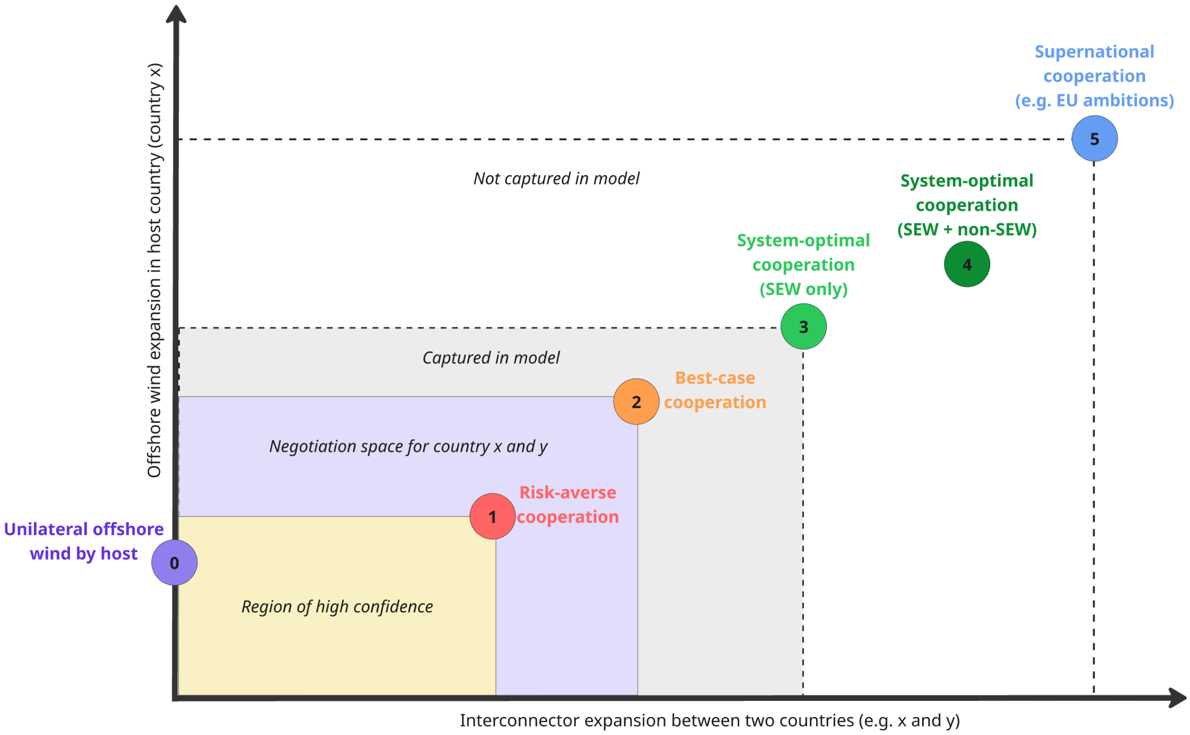



**Figure 6.2:** Illustration of different investment outcomes depending on cooperation levels

- **Level 0: Unilateral offshore wind by host -** The minimum level of offshore wind expansion expected when the host country meets its wind needs independently, as confirmed by the results in section 5.1. Here, no simultaneous expansion of interconnection capacity, i.e., no reinforcement of the onshore grid between the two price zones is constructed.
- **Level 1: Risk-averse cooperation -** The expansion point under agreements covering both offshore wind and interconnector investments corresponding to the best-case of region of high certainty, where both countries can align their expectations about future market conditions and expected benefits justify investment.
- **Level 2: Best-case cooperation -** Within the negotiation space defined by the cost-sharing mechanism, the best-case point represents the agreed-upon expansion that maximizes system-wide SEW within that space.
- **Level 3: System-optimal cooperation (SEW only) -** This point represents the offshore wind and interconnector expansion that maximizes system-wide SEW. This is the maximal expansion captured within the analytical model.
- **Level 4: System-optimal cooperation (SEW + non-SEW) -** This expansion point represents the potential for more investment in offshore wind and interconnector had the additional non-SEW benefit indicators in Table 1.1 been considered.
- **Level 5: Supranational cooperation -** This hypothetical expansion point represents a highly ambitious level of offshore wind and interconnector development in the bilateral setting, analogous to long-term EU targets such as those for 2050 (European Commission, 2026). It reflects the scale of investment that the two countries would need to undertake to align with such objectives. However, as the model does not evaluate a specific target scenario, the exact positioning of this point relative to the others (1-4) is purely speculative. It may lie close to the local optimum or significantly beyond it, depending on how these targets are defined, the countries in question, as well as on prevailing and future market conditions.

As illustrated in Figure 6.2, progressing along the cooperation trajectory from unilateral investment at Level 0 toward the system-optimal and supranational ambitions of Levels 4 and 5 requires increasingly sophisticated coordination between countries. Ministry of Economic Affairs and Climate Policy (EZK), Netbeheer Nederland (NBNL), and Authority for Consumers and Markets (ACM) (2024) reinforces this by stating that Member States must share the costs of radial offshore infrastructure when benefits spill over to non-host countries, confirming that cross-border cost-sharing agreements are not optional but a prerequisite.

Because the quantitative model is bilateral, the implications for wider North Sea cooperation are necessarily interpretive. The following discussion extrapolates from the model's bilateral findings and combines them with the reviewed policy literature to identify challenges that may arise when moving from bilateral to regional cost-sharing arrangements.

### 6.2.1. EU financing instruments (CEF) and Grids Package gap-filling instrument as cost-reduction levers

European Commission (2024) explicitly notes that CEF can be particularly effective in covering net-negative impacts perceived by a hosting Member State. Additionaly, the cost sensitivity analysis shows that lower infrastructure costs shift equilibrium outcomes toward higher investment. CEF funding directly reduces effective CAPEX for both participating countries (European Climate, Infrastructure and Environment Executive Agency (CINEA), 2025), which in the bilateral setting maps onto a shift in the cost parameters that the model shows to be welfare-improving. PCI status remains attainable even for nominally domestic projects provided that at least 10% of project benefits accrue to a neighboring state (Willems et al., 2025), which is shown to be possible even in the case of a unilateral expansion of offshore wind (model results). By deliberately scoping projects to accommodate cross-border benefits, spillovers may naturally exceed this threshold and make them CEF-eligible.

The EU Grids Package, European Commission, 2025a, introduces a gap-filling role under which the Commission may intervene in persistent negotiation deadlocks, and additionally proposes project bundling, use of congestion income for PCI/PMI financing, and special purpose vehicles. These are instruments that, if operationalized, could produce cost-reducing effects consistent with the model's sensitivity results. However, the package does not clarify how costs would be allocated in the event of intervention, leaving the gap-filling role disconnected from any concrete cost-sharing mechanism. The Dutch government's response reflects this directly, welcoming the principle while insisting that cost-sharing arrangements must be made concrete before the instrument can be relied upon (Ministerie van Klimaat en Groene Groei, 2025a). Until these ambiguities are resolved, the gap-filling role remains a political signal rather than an actionable instrument.

### 6.2.2. Incorporate non-SEW benefits into cost-sharing frameworks

The analytical model exclusively captures SEW-based benefits as the basis for evaluating cost-sharing outcomes. As illustrated in Figure 6.2, Level 4 recognises that broader non-SEW benefit indicators presented in Table 1.1 such security of supply, energy independence, contribution to RES targets, and industrial development could justify investment beyond the SEW-based system optimum. These benefits are acknowledged in both the ENTSO-E CBA guidelines (ENTSO-E – European Network of Transmission System Operators for Electricity, 2023) and the OTC (Offshore TSO Collaboration (OTC), 2025), but remain largely non-monetized due to the absence of agreed quantitative methodologies that would, in the end, have to put a price on these benefit indicators along the lines of €/MWh or €/MW.

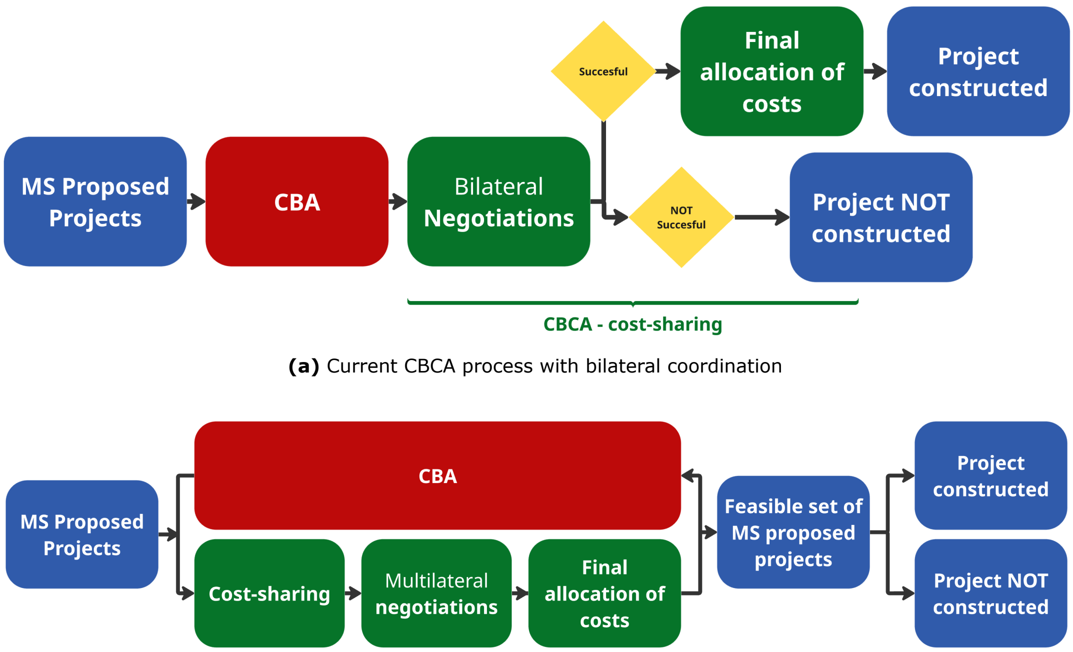
Offshore TSO Collaboration (OTC) (2025) recommends their inclusion via a fixed fee[3], noting that non-SEW benefits should in principle be sufficient to drive voluntary participation. However, their inclusion is not straightforward. As Roth, Tagliapietra, and Zachmann

[3] Where each participating country would recognize a fixed amount for the non-quantifiable benefits in terms of €/MWh or €/MW.

(2026) illustrate, increased integration produces distributional effects that cut differently across domestic stakeholder groups, and there is limited political appetite for the cross-border transfers needed to compensate losers. Security of supply adds a further layer of complexity: a country's perception of supply security depends on its own generation profile and on the current and expected future state of its neighbours' systems (Roth et al., 2026), making uniform non-SEW valuations inherently contested across cooperating parties. Fixed ex-ante contributions therefore remain the only politically tractable approximation under current institutional conditions, despite their imprecision.

### 6.2.3. Repositioning the cost-sharing timeline

As illustrated in Figure 2.1, cost-sharing enters the infrastructure planning process only as a final step and leaves countries to voluntarily participate if and only if a feasible agreement can be found. This positions cost-sharing as purely redistributive rather than a structuring force in decision-making. The logic of the present analytical framework suggests that embedding cost-sharing constraints earlier in the planning process may produce more implementable outcomes: rather than hoping a feasible agreement space exists after CBAs are completed, projects could be identified under conditions that guarantee one does. OTC (2025a) claim on the existence of a structural disconnect between the CBA and the CBCA is on par with how its effects can be mitigated using this approach. Figure 6.3 shows the alternative placement of the cost-sharing element.




**(a)** Current CBCA process with bilateral coordination



**(b)** Multilateral negotiation-based CBCA process

**Figure 6.3:** Comparison of CBCA process structures

There is a concern that additional cost-sharing constraints leave ambitious infrastructure targets off the table, but its force is limited as a project for which no cost-sharing agreement was ever within reach was unlikely to be built regardless. More substantially, this approach may reduce the expectation-sensitivity that was identified across all mechanisms in the results. Since TYNDP scenarios are built from Member State inputs (Willems et al., 2025), a collective cost-allocation exercise embedded at the planning stage could align national perspectives on the future energy system with a shared regional vision.

Additionally, also confirmed with the results of the model, countries can choose not to invest in any infrastructure even when they have welfare-improving economic incentive to do so (for external reasons). Thus, repositioning the cost-sharing element to go hand-in-hand with the CBA would not guarantee investment but would at minimum ensure that the projects which do advance are those for which a cooperative agreement is structurally attainable and reduce the risk of welfare-improving infrastructure failing at the negotiation stage rather than on its economic merits.

### 6.2.4. The role of a third party: EU funding and gap-filling

CEF funding and the Commission's gap-filling power (Section 2.2) let the EU enter the bilateral problem, and they address two distinct reasons a welfare-improving expansion can fail. The first is strategic: a mutually acceptable outcome may exist within the negotiation space, yet the no-investment state remains an equilibrium under the min-rule, so either country can block it. The second is feasibility: a more ambitious outcome may lie outside the negotiation space, because at that level one country is left worse off than under the status quo.

CEF support acts on the cost side and therefore bears on feasibility rather than coordination. Lowering the capital cost a country must recover raises its net benefit at a given level, widening the negotiation space and shifting the welfare-maximising outcome outward; it does not, however, dislodge the no-investment outcome, since no support is paid where nothing is built. Its sharper use depends on allocation: a flat per-MW contribution is split through the existing cost-allocation key, whereas support directed at the country that would otherwise be left worse off would act as an externally funded compensating transfer, capable of drawing an otherwise loss-making level back inside the space. As specified, the model admits CEF only as a reduction in shared cost distributed through that key, so this targeted use is a reinterpretation the framework points to rather than one tested here.

The gap-filling power addresses the strategic failure funding cannot. By imposing an outcome where a country would otherwise propose nothing, it overrides the min-rule veto. Whether this is benign depends on where the imposed outcome falls: inside the negotiation space it resolves a coordination failure, selecting an outcome both countries already accept; outside it, at least one is left worse off and would need a compensating transfer the function does not provide.

Taken together, the two instruments reframe the process rather than its findings. The bilateral negotiation is no longer self-contained: it sits within a wider, EU-overseen structure (Section 2.2) in which external funding can shift the terms of an agreement and a backstop authority can act on a deadlock. The comparative results are unaffected: how the mechanisms rank, and how the scope of shared costs shapes the negotiation space, describe the interaction between the two countries rather than the EU's role. What changes is the standing of the model's two central objects: the negotiation space, once the set of outcomes the countries could reach unaided, becomes the baseline against which the third party's contribution is measured, while the no-investment outcome shifts from a possible terminal state to the point at which external action becomes relevant. The efficiency loss between the strategic outcome and the system optimum, unchanged as a quantity, thereby gains a second reading as the room within which a third party can act.

## 6.3. Model limitations

The model adopts a stylized structure to isolate the incentive effects of cost-sharing mechanisms. This abstraction, however, comes at the cost of reduced representativeness of real-world market, regulatory, and physical system complexities, thereby limiting the direct applicability of the results for policy guidance. This section individually discusses these categories of limitations of the approach to the research problem.

### 6.3.1. Design, structural and economic limitations

The present modeling framework resembles a simplified bilateral coupled market that simulates the effective changes on prices and resultant surpluses for consumers, producers and the congestion revenues for a given static definition of the involved countries profiles for both supply and demand. The model evaluates two countries, operating under predefined conditions with given likelihoods of occurrence, respond to additional offshore wind generation or interconnection capacity. A key structural bottleneck with this approach is the probabilities of congestion and import/export regimes are exogenously specified and remain invariant to infrastructure expansion. In practice, however, investments in generation and transmission capacity would endogenously influence market conditions, altering the frequency of congestion events and the direction and magnitude of cross-border trade flows. This may lead to an underrepresentation of the full range of benefits associated with interconnector expansion. While additional offshore wind capacity could increase congestion during $x \to y$ export periods, this would, in turn, influence the value of both new and existing transmission infrastructure, as well as the marginal benefit of further wind deployment. This simplifying assumption is also present in Kristiansen et al. (2018).

Offshore wind investments are treated exogenously and evaluated outside a system-wide planning framework. Rather than optimizing towards a predefined deployment target (such as an alignment with ENTSO-E's TYNDP 2026, which would be synergetic to the approach of Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC) (2026)), the model evaluates how much investment emerges under different cost-sharing mechanisms. This reverses the real-world planning logic, where investment targets are typically set exogenously and cost-sharing mechanisms are designed to enable their realization. This "reversed" approach does not take away from the ground for comparison between the cost-sharing mechanisms, and may actually contribute to providing a new perspective to such analyses.

The bilateral structure of the model excludes potential effects on non-host third-countries, which may play an important role in real-world multilateral systems. In interconnected electricity markets, investments in generation and transmission can induce indirect welfare effects beyond the directly involved countries (Willems et al., 2025). As a result, the model does not capture how such third-party impacts may alter the distribution of benefits or influence the design and acceptance of cost-sharing mechanisms.

The model does not account for the possibility of distinguishing between two separate project sets: one corresponding to the unilateral offshore wind investment by country $x$, and another specifically designed to capture additional benefits for country $y$. In practice, such a distinction would likely be necessary in real-world cost-sharing discussions, but it is not incorporated in the present analysis.

Furthermore, the analysis does not benchmark outcomes against a theoretically optimal allocation, such as the Shapley Value. As a result, while mechanisms can be compared relative to one another, it is not possible to assess how closely they approximate an ideal notion of fairness, as established in the work of Kristiansen et al. (2018). The mismatch metric still provides useful results that represents the degrading fairness in allocation when certain costs are omitted from cost-sharing agreements or via the use of imperfect ex-ante sharing keys.

Among the model's economic simplifications, two are particularly prominent in constraining its applicability: the assumption of perfect information and the use of simplified linear curves to represent the supply and demand profiles of countries $x$ and $y$. The primary limitation arising from the assumption of perfect information is that each player in the strategic investment game is assumed to have full knowledge of future flows, payouts, and ex-post transfers, which in reality would be uncertain and only approximated through expectations or forecasts. As a result, the model relies on gains and losses derived from these sources to determine investment decisions, thereby neglecting the uncertainty and risk that would be inherent in real-world settings.

The use of linear supply and demand curves constitutes a strong simplification of real electricity market dynamics. In contrast to bid-based spot markets, where prices emerge from discrete offers and strategic behavior, the model imposes a continuous and smooth representation of supply and demand. As a result, non-linearities such as abrupt price changes, capacity-driven price spikes, and strategic bidding effects are not captured, which may influence strategic investment decisions.

The Nash game captures non-cooperative investment decisions but abstracts from delay tactics, signaling, and free-riding strategies that may arise in real negotiations, the full range of which are not captured by this approach.

Finally, risk and financing considerations are not explicitly modeled. Investment decisions are evaluated from a system welfare perspective, without accounting for investor risk aversion, financing constraints, or differences in cost of capital across countries, which are known constraints in offshore wind and transmission infrastructure (Offshore TSO Collaboration (OTC), 2025).

### 6.3.2. Cost-sharing mechanism design limitations

Across all cost-sharing configurations, only CAPEX is included. In Table 2.2, cost components are identified as DEVEX, CAPEX, cost of capital, and OPEX. As a result, the full range of cost components is not accounted for in the present analysis.

### 6.3.3. Calibration, interpretation, and external validity

As described more extensively in subsection 4.9.1, the input parameters of the model are chosen to simulate a hypothetical scenario with two predefined countries. The parameters are tuned via trial and error to reflect the desired conditions and yield results within the considered expansion grid.

While some parameters such as the existing interconnection capacity and renewable installation are inspired from real-world amounts, remainder of the parameters do not reflect actual magnitudes. As a result, scale of the resultant numerical values may be off compared to expectations in real life. For instance, in their study analyzing welfare effects of interconnection between Ireland and Great Britain, Malaguzzi Valeri (2009)'s simulation results indicate a marginal net benefit gain of 70,000–160,000 €/MW (2005 euros) for additional interconnection; whereas this value is only approximately 1,047 €/MW in the present analysis. This discrepancy does not undermine the validity of the present results, as the objective is not to produce quantitatively accurate real-world estimates. Rather, the results should not be interpreted as reflecting real-world magnitudes.

Additionally, discussions with internal stakeholders from the Ministry of Climate Policy and Green Growth highlighted that the methodological approach of this research aggregating stakeholders to the country level overlooks potential misalignments of incentives between actors involved in financing, owning, and operating infrastructure such as TSOs, governments, regulators, and private investor. In retrospect, Kristiansen et al. (2018) adopts a similar approach by treating each country as an aggregated entity, modeling them as players in a multilateral cooperative investment framework. This country level aggregation is also observed in Willems et al. (2025) and Offshore TSO Collaboration (OTC) (2025)'s conceptual examples with SEW-based assessments of cost-sharing methodologies. While potential incentive misalignment between internal stakeholders within a single country are not explicitly captured in the performance evaluation of cost-sharing configurations or in the decision-making structure of the market-clearing optimization problem, this simplification appears to be standard practice within the limited body of available literature.

On a similar note, the institutional implementation of mechanisms $\text{CfD}_{\text{trans}}$ and $\text{CfD}_{\text{gen}}$ is not modeled. In particular, the analysis does not specify how strike prices would be determined, which entity would administer payments, or how enforcement and compliance would be ensured across jurisdictions. Instead, countries are represented as aggregated beneficiaries and payers of all transactions. Modeling this in the given setup requires extensive knowledge on legal frameworks and financial transactions involved in cross-border infrastructure financing, regulatory design, and contractual settlement mechanisms. These aspects are beyond the scope of this particular experiment.

The overall implication of the stakeholder simplification is that some of the expansion outcomes identified by the model may not materialize in practice. In reality, individual stakeholders within a country could oppose such outcomes, particularly in cases where their respective surplus changes are negative. For instance, Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC) (2026) state that revenues for TSOs in cross-border projects must adequately reflect the costs and risks of investment. However, across all considered cost-sharing scenarios, the proportionality between infrastructure investment costs (CAPEX) and the benefits directly accrued by TSOs is not ensured.

### 6.3.4. Recommendations for further research

The limitations identified across section 6.3 point to concrete directions for future research. Each category of limitation suggests a corresponding pathway through which the analytical framework can be extended and refined. Table 6.2 maps each limitation category to a set of targeted recommendations, with the aim of progressively closing the gap between the stylized analysis conducted here and the complexity of real-world cross-border cost-sharing negotiations.

**Table 6.2:** Recommendations for further research by limitation category

| Category | Recommendations for further research |
|---|---|
| Design and structural limitations | • Apply the present methodological approach to a multilateral setting involving more than two countries.<br>• Model congestion and import/export states dynamically to capture how offshore wind and interconnector expansion affect the probability of each operating condition — and therefore the benefits each party receives.<br>• Treat offshore wind investment by a merchant developer endogenously within the optimization problem to expand the scope of negotiations to include the developer's business case. |
| Economic assumptions | • Introduce a meaningful counterfactual to cooperation, such as an alternative investment opportunity available to either party, so that the decision to cooperate reflects not just mutual net benefit but also the opportunity cost of doing so.<br>• Endogenously incorporate risk and financing considerations, including investor risk aversion, financing constraints, and differences in cost of capital across countries, into the decision-making structure. |
| Calibration, interpretation, and external validity | • Explore actor-level interactions in settings where stakeholders (consumers, producers, TSOs, and the state) are not aggregated at the country level. |

On top of addressing the identified limitations, academia can benefit future research that specifically focuses on the legislative side. A substantial portion of the cost-sharing challenge is regulatory and legal rather than purely economic. For the mechanisms identified as economically sound in this analysis to be implemented in practice, they must be compatible with and integrated into the broader governance structures of the European energy regulatory framework. It is therefore recommended that future research systematically examines where these mechanisms stand in relation to existing legislation, and what changes or adaptations would be required to bring them into alignment with current and forthcoming EU regulation.

A related avenue concerns the cross-sectoral dimension of offshore infrastructure planning. The present analysis is confined to electricity market effects, yet the revised TEN-E Regulation explicitly mandates ENTSO-E and ENTSO-G to cooperate on integrated Union-wide network development plans based on a shared ”one energy system” modelling approach with consistent methodologies across energy carriers (European Union, 2022; European Commission, 2025e). As offshore wind assets increasingly serve dual roles as both electricity exporters and potential hydrogen producers, the benefits and costs they generate will spill across sector boundaries, which is a dynamic already visible in OTC assessments showing significant welfare gains in both electricity and hydrogen markets from the same set of offshore projects (OTC, 2025a). How cross-border cost-sharing agreements should account for benefits accruing in the gas and hydrogen networks rather than the electricity market alone remains an open question, and one that the framework developed in this thesis could in principle be extended to address.

Finally, it is recommended to investigate whether other industries that face structurally similar cross-border coordination challenges have developed cost-sharing principles or governance frameworks that could offer transferable lessons. Potentially relevant domains include telecommunications, where undersea cable infrastructure spans multiple jurisdictions; transportation, where cross-border rail and highway networks distribute benefits across countries; and defence, where joint development costs are shared among allied states under arrangements such as NATO burden-sharing. Whether and to what extent the solutions developed in these contexts can be adapted to the offshore wind and interconnector setting warrants dedicated investigation.

# 7

# Conclusion

This chapter synthesizes the findings of the thesis into answers to the research questions and draws broader implications for policy and practice. Section 7.1 addresses each research question in turn, culminating in an answer to the main research question. Section 7.2 translates these findings into targeted policy recommendations for the Ministerie van Klimaat en Groene Groei. Section 7.3 reflects on the societal and scientific relevance of the research.

## 7.1. Answers to the research questions

The research questions are answered in sequence, each building on the preceding one. RQ1 establishes the distributional problem that cross-border offshore infrastructure creates. RQ2 evaluates how different cost-sharing mechanism designs perform under non-cooperative conditions. RQ3 examines the extent to which governance and implementation considerations can overcome the constraints those mechanisms face in practice. Together, their answers converge into a response to the main research question.

### 7.1.1. RQ1 - Cross-border benefits, national cost burdens

> *How does the cross-border nature of offshore electricity infrastructure create distributional challenges that existing regulatory and policy arrangements struggle to overcome?*

The graphical analysis in chapter 3 reveals that benefits from offshore wind and interconnector expansion leak cross-border regardless of the infrastructure configuration, yet the distribution of these benefits across countries and the individual stakeholder groups within is highly uneven and deeply sensitive to underlying market conditions. No scenario can be predicted with certainty, meaning that who gains and who bears costs depends heavily on assumptions that cannot be fixed ex-ante. The analysis further demonstrates that the host country carries a disproportionate structural burden for radial connections, even when a significant share of the benefits accrue elsewhere, which is a distributional asymmetry that no current framework adequately corrects for.

The literature reviewed in Chapters 3 and 4 confirms that this is not merely a technical challenge but a governance one. The CBCA, despite its legislative intent, has defaulted to the territorial principle in over 70% of decisions, producing little to no cross-border redistribution in practice. Its narrow scope that limits the applicability to PCI projects and CAPEX-only considerations, combined with its complexity, scenario-dependence, and reliance on voluntary bilateral agreement, renders it structurally ill-suited to address the offshore cost-sharing problem at scale. Alternative mechanisms such as ITC and CID have similarly been found inadequate, while injection charges and EU-wide tariffs raise unresolved questions of regional applicability. To top it all, the Grids Package signals awareness of the problem but leaves the methodological core unresolved.

Taken together, the cross-border nature of offshore electricity infrastructure creates a fundamental mismatch: benefits are regional, but costs are national, and the frameworks tasked with bridging this gap lack either the scope, the enforceability, or the methodological clarity to do so.

### 7.1.2. RQ2 - Mechanism design under non-cooperative conditions

*Under non-cooperative investment conditions, how do different cost-sharing mechanism designs influence the efficiency, fairness, and stability of agreed offshore infrastructure expansion outcomes?*

The model results in chapter 5 consistently demonstrate that under non-cooperative conditions, countries underinvest relative to the system-wide optimal benchmark. This is a direct consequence of what the cross-cutting analysis in chapter 6 identifies as the coordination problem: a cost–benefit asymmetry that drives countries toward a unilateral approach focused solely on national welfare gains, leading to inefficient utilization of offshore wind potential.

On ex-ante allocation alone, benefit-proportional cost sharing outperforms a fixed 50-50 split by more accurately reflecting each country's real accrued benefits, bringing agreed expansion closer to the system optimum. However, ex-ante mechanisms as a whole prove fragile: equilibrium regions are narrow and fragmented, and no ex-ante configuration reliably converges toward the welfare-maximizing solution across varying market expectations.

Introducing ex-post correction through Kristiansen et al. (2018)'s transmission CfD yields systematic improvement in investment efficiency, consistently reinforcing the complementarity between offshore wind and interconnection capacity. However, it is not a plug-and-play instrument as an incorrectly calibrated strike price can produce outcomes worse than the ex-ante benchmark alone, and the scale of ex-post transfers raises serious practical concerns: the non-host country may be exposed to obligations covering the majority of total costs that are, by design, unknown prior to project realization. The cross-border generation CfD, by contrast, expands the feasible negotiation space but does not primarily function as a redistribution mechanism. It rather operates as an additional cost component, and critically, transfers investment risk to a non-host country that retains limited control over the underlying infrastructure and market conditions. Expanding cost-sharing scope to include all cost components can improve outcomes, but this should be paired with a sharing rule that re-calibrates with the broader cost base. Layering both ex-post instruments simultaneously does not monotonically improve performance either because their interaction reshapes rather than extends the strategic incentive structure.

Cutting across all mechanisms, no configuration produces equilibrium outcomes that are stable under divergent expectations about future market conditions. Beyond a result of the modeling exercise, this reflects a real governance challenge: without a shared forecasting framework or agreed scenario structure between countries, the stability of any cost-sharing agreement remains inherently fragile, regardless of its mechanical design. Mechanism design alone is insufficient; institutional alignment on market expectations is a necessary complement to any instrument.

### 7.1.3. RQ3 - Governance, structure, and methodological considerations as implementation enablers

*To what extent can design considerations overcome constraints on implementing the proposed cost-sharing mechanisms?*

The implementation analysis in Section 6.1 reveals that the concerns on the practical applicability of the CfD for transmission can be mitigated. Calibration circularity, where the strike price depends on realized benefits that in turn depend on the strike, can be addressed through ex-ante agreed benefit forecasts anchored to a predefined divergence threshold, triggering periodic recalibration. A budgetary correction cap further restores ex-ante cost predictability, at the cost of limiting the corrective capability of the instrument. These design choices do not eliminate the fundamental trade-off between predictability and flexibility- but make it governable. What remains structurally unresolved is the regulatory embedding of the instrument: who owns the contract, how settlements flow through the tariff base, and how it interacts with TSO revenue regulation. Until these questions are answered, the CfD for transmission is an analytically effective instrument operating without a defined legislative boundary.

The incidence analysis in Subsection 6.1.2 shows that costs ultimately pass through to electricity consumers across all mechanisms via network tariffs, levies, or government budgets; whereas producers benefit from market coupling without bearing investment costs. This asymmetry is not addressed by any of the cost-sharing configurations. The bargaining analysis in subsection 6.1.3 further demonstrates that structural asymmetries persist even when a feasible agreement space exists: the host country holds informational advantages, both parties face incentives to game the CfD mechanisms through their domestic RES investment trajectories, and fallback positions are fundamentally unequal- which may deter future cost-sharing exercises due to temporal dependency of benefits between subsequent investments. These constraints are recognized as valid concerns that transparency requirements and building on established bilateral trust can mitigate. However, mechanism design alone does not resolve bargaining asymmetries structurally; it only determines how exposed they become.

The cooperation trajectory framed in Section 6.2 shows that moving from unilateral investment toward the system-optimal and supranational ambitions require increasingly sophisticated institutional alignment, not just better financial instruments. EU financing through CEF directly reduces effective CAPEX and is already compatible with projects where even unilateral offshore wind expansion generates spillover benefits meeting the 10% cross-border threshold, through the PCI status. The Grids Package's gap-filling role introduces additional cost-reduction levers, but remains a political signal without a concrete cost-sharing methodology attached to it. The incorporation of non-SEW benefits could push investment beyond the SEW-based system optimum, but these benefits are non-monetized and contested across parties. Finally, repositioning cost-sharing earlier in the planning process as a structuring constraint rather than a final redistributive step is identified as a methodological lever that could produce more implementable outcomes by design, rather than contingently hoping a feasible agreement space emerges after CBAs are completed.

### 7.1.4. MRQ - Cross-border collaboration for the North Sea electricity infrastructure

*What cross-border collaboration model would enable the effective development of a large-scale offshore electricity system in the North Sea while reflecting participating countries' differing costs, benefits, and risks?*

Offshore wind and interconnector expansion generate mutually reinforcing benefits that spill across borders, while their costs remain largely national—borne by consumers through grid tariffs and by public budgets, which is a mismatch that current cost-sharing frameworks fail to effectively address. The cross-border collaboration model that would overcome this asymmetry, and pave the way towards the effective development of the North Sea electricity grid designed to maximize collective regional welfare, first requires institutional alignment on market expectations, synergy between national and regional energy infrastructure development plans, and mutual trust between Member States to overcome negotiation deadlocks arising from the sensitivity of expected benefits to these elements.

The answer to the main research question is therefore a synthesis of the model results, the policy and literature review, and the implementation considerations discussed in Chapter 6. The cost-sharing methodology embedded into this cross-border collaboration model should use benefit-proportional allocation ex-ante, with a scope that covers as many cost components as possible—including supporting assets such as the radial link connecting the wind farm to the onshore grid—while recognizing that coupling transmission and generation projects under a joint cost-sharing agreement enhances their cross-border benefit value, ensures that these benefits underpin eligibility for EU financial support instruments (e.g. CEF under PCI status), reduces the effective capital expenditure for participating states, and structures generation support schemes on a cross-border basis through a jointly shared $\mathrm{CfD}_{\mathrm{gen}}$, which — by making the non-host country a co-investor in generation support — expands the feasible negotiation space beyond what ex-ante cost allocation alone can achieve. Complementary to the ex-ante allocation, the ex-post CfD for transmission, calibrated cyclically to both expected and realized benefits, and governed by an ex-ante defined divergence threshold (minimum mismatch triggering the CfD) and correction cap (limit on adjustment volume), should be used to provide flexibility under evolving market conditions while preserving predictability for investors.

While this cross-border collaboration model defines the building blocks of effective bilateral cooperation, its extension to the greater North Sea introduces challenges that must be resolved. To address these challenges, non-SEW benefit indicators such as security of supply, energy independence, and renewable target contributions should be incorporated through fixed ex-ante contributions where monetization is absent, and cost-sharing constraints should be embedded in parallel to the cost-benefit assessments (CBA) as a structuring force rather than a final redistributive step. Even then, bargaining asymmetries, host country informational advantages, and the temporal dependency of asset-specific benefits create conditions under which large-scale multilateral cooperation will likely become harder to achieve. At the same time, the regulatory treatment and legal embedding of both CfD instruments remain unresolved.

This collaborative model should therefore serve as a target architecture rather than a ready-to-deploy solution that is best pursued by building first on established bilateral trust before scaling to the broader North Sea. Whether it ever gets there depends on the willingness of Member States to commit to the bureaucratic complexity these instruments and collective approach demand, and to treat the North Sea as a shared supranational mission rather than a collection of national ones.

## 7.2. Policy recommendations for the Ministry

The findings of this research carry direct relevance beyond the analytical domain, extending into the economic and policy decisions that the Ministry of Climate Policy and Green Growth faces in the near term.

The following recommendations translate the thesis findings into policy-relevant actions for the Ministry. They should be understood as strategic recommendations informed by the model and literature, rather than as direct quantitative outputs of the simulation framework. The recommendations are organized by their scope of application: those that can be initiated internally within the Ministry, and those that require engagement with external stakeholders across the regulatory, institutional, and intergovernmental landscape.

### 7.2.1. Internal actions

The internal recommendations concern actions that fall within the Ministry's own remit or can be pursued in coordination with other Dutch ministries, without requiring consultation with external entities.

- *Consider* advocating for PCI status for offshore wind projects even when nominally domestic in order to unlock CEF eligibility and reducing effective CAPEX for the Netherlands. Application for CEF status should be made a higher priority overall.
- *Consider* reviewing the implications of extending the domestic CfD for generation (SDE++) towards a cross-border setting. It is likely more projects with a shared support-scheme will materialize in the coming decade, thus it is best to prepare the national CfD structure to be "shareable" cross-borders with fewer complications.

- *Consider* commissioning internal research on:
  - How the Netherlands values each non-SEW benefit relative to North Sea neighbors, as this determines the Netherlands' negotiating position on non-monetized contributions
  - The opportunity cost of maritime space allocated to offshore wind, particularly when the scale could accommodate cross-border benefits, which is a cost component currently missing from cost-sharing frameworks
  - How infrastructure costs, which currently fall entirely on consumers via tariffs, could be more broadly distributed across stakeholder groups at the EU scale.
- *Do not leave* cost-sharing for radial off the table. The results show it improves outcomes economically. *Develop* a political pathway to making it acceptable in bilateral negotiations.
- *Engage* in discussions with the Ministry of Infrastructure and Water Management on lessons learned from cross-border infrastructure domains such as rail, highways, or telecommunications.

### 7.2.2. External actions

The external recommendations concern actions that require engagement beyond the Dutch institutional landscape, involving regulators, TSOs, intergovernmental bodies, and EU institutions whose mandates and decisions directly shape the conditions under which cross-border cost-sharing can be designed and implemented.

- *Engage* in discussions with the European Commission to establish a regionally agreed-upon scenario assessment framework that is more binding than voluntary participation, grounded in a shared regional vision that all North Sea member states formally endorse. The results show that no cost-sharing mechanism produces stable outcomes without aligned expectations on future market conditions.
- *Engage* in discussions with the European Commission to clarify how a CfD for transmission (or any instrument serving the same ex-post correction function) sits within the existing EU regulatory framework, and what legislative adaptations would be required to operationalize it.
- *Continue* collaborating within OTC-NSEC (via TenneT) on the cost-sharing methodology development.
- *Collaborate* with neighboring energy ministries and their respective TSOs to establish a joint generation and transmission planning framework for the North Sea, where offshore wind deployment targets and interconnection capacity are developed simultaneously toward a shared regional ambition.
- *Engage* in discussions with ENTSO-E to embed cost-sharing constraints earlier in the TYNDP process.

## 7.3. Societal and SET Relevance

To conclude, expanding offshore wind in the North Sea offers a concrete path to cheaper, cleaner, and more secure energy. However, this requires countries to jointly invest in cross-border infrastructure, and agreeing on who pays for what has proven politically challenging. The barriers to cooperation are not technical, but economic and institutional. Without resolving them, the infrastructure will not get built. This research directly addresses that governance problem, providing analytical tools to evaluate which cost-sharing mechanisms can make cross-border cooperation work in practice, ultimately enabling the energy transition that European citizens depend on.

This thesis both draws on and extends the knowledge developed throughout the MSc SET programme. The programme provided a solid foundation in the technical and economic operation of electricity grids and energy markets, with a particular focus on renewable energy integration. Core concepts such as optimization, market clearing, and coupled European electricity markets were directly applied and built upon throughout this research. Beyond the programme's scope, however, this thesis required engaging with the macro-scale political and institutional dimensions of energy infrastructure that connect to the real-world governance challenges where national interests, regulatory frameworks, and negotiation dynamics all play a decisive role. In doing so, it served as a valuable bridge between the analytical toolkit acquired during the MSc and the complex, multi-actor reality in which energy policy is actually made.

# A

# Linear Optimization Problem Solutions

All solutions have been validated using *Wolfram Mathematica*[1]. For the presented expressions, assume that each global parameter (without a regime-index) corresponds to the regime-specific parameter within its corresponding regime. Furthermore, the following should be noted:

$$\begin{aligned} K' &= K + \Delta K, \\ q'_{x,\text{RES}} &= q_{x,\text{RES}} + \Delta q_{x,\text{RES}}. \end{aligned} \tag{A.1}$$

## A.1. Solution for Case 1 and 2 - L0G00x and L0G00y

$$q_x = \frac{a_{Dy}a_{Sx}a_{Sy}\left(q'_{x,\text{RES}} + q_{y,\text{RES}}\right) + \bar{\lambda}_x\left(a_{Dy}a_{Sx} + a_{Dy}a_{Sy} + a_{Sx}a_{Sy}\right) - \bar{\lambda}_y\left(a_{Sx}a_{Sy}\right)}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}$$

$$q_y = \frac{a_{Dx}a_{Sx}a_{Sy}\left(q'_{x,\text{RES}} + q_{y,\text{RES}}\right) + \bar{\lambda}_y\left(a_{Dx}a_{Sx} + a_{Dx}a_{Sy} + a_{Sx}a_{Sy}\right) - \bar{\lambda}_x\left(a_{Sx}a_{Sy}\right)}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}$$

$$f = \frac{a_{Dx}a_{Sx}\left(a_{Dy} + a_{Sy}\right)q'_{x,\text{RES}} - a_{Dy}a_{Sy}\left(a_{Dx} + a_{Sx}\right)q_{y,\text{RES}} + a_{Sy}\left(a_{Dx} + a_{Sx}\right)\bar{\lambda}_y - a_{Sx}\left(a_{Dy} + a_{Sy}\right)\bar{\lambda}_x}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Dy}a_{Sx}a_{Sy}}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}, \frac{\partial q_x}{\partial \Delta K} = 0$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Dx}a_{Sx}a_{Sy}}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}, \frac{\partial q_y}{\partial \Delta K} = 0$$

$$\frac{\partial f}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Dx}a_{Sx}(a_{Dy} + a_{Sy})}{a_{Dx}a_{Dy}a_{Sx} + a_{Dx}a_{Dy}a_{Sy} + a_{Dx}a_{Sx}a_{Sy} + a_{Dy}a_{Sx}a_{Sy}}, \frac{\partial q_x}{\partial \Delta K} = 0$$

[1] https://www.wolfram.com/mathematica/

## A.2. Solution for Case 3 - L0G10

$$q_x = q'_{x,\text{RES}} - \frac{a_{Sy}\left(a_{Dx}q'_{x,\text{RES}} - \bar{\lambda}_x + \bar{\lambda}_y\right) - a_{Dy}\left(-a_{Dx}q'_{x,\text{RES}} + a_{Sy}q_{y,\text{RES}} + \bar{\lambda}_x\right)}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}$$

$$q_y = \frac{a_{Sy}\left(a_{Dx}\left(q'_{x,\text{RES}} + q_{y,\text{RES}}\right) - \bar{\lambda}_x + \bar{\lambda}_y\right) + a_{Dx}\bar{\lambda}_y}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}$$

$$f = \frac{a_{Sy}\left(a_{Dx}q'_{x,\text{RES}} - \bar{\lambda}_x + \bar{\lambda}_y\right) - a_{Dy}\left(-a_{Dx}q'_{x,\text{RES}} + a_{Sy}q_{y,\text{RES}} + \bar{\lambda}_x\right)}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\text{RES}}} = 1 - \frac{(a_{Sy} + a_{Dy})a_{Dx}}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}, \frac{\partial q_x}{\partial \Delta K} = 0$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Sy}a_{Dx}}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}, \frac{\partial q_y}{\partial \Delta K} = 0$$

$$\frac{\partial f}{\partial \Delta q_{x,\text{RES}}} = \frac{(a_{Sy} + a_{Dy})a_{Dx}}{a_{Dx}\left(a_{Dy} + a_{Sy}\right) + a_{Dy}a_{Sy}}, \frac{\partial f}{\partial \Delta K} = 0$$

## A.3. Solution for Case 4 - L0G01

$$q_x = \frac{a_{Dy}\left(a_{Sx}\left(q'_{x,\text{RES}} + q_{y,\text{RES}}\right) + \bar{\lambda}_x\right) + a_{Sx}\left(\bar{\lambda}_x - \bar{\lambda}_y\right)}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}$$

$$q_y = q_{y,\text{RES}} + \frac{-a_{Dy}q_{y,\text{RES}}\left(a_{Dx} + a_{Sx}\right) + a_{Sx}\left(a_{Dx}q'_{x,\text{RES}} - \bar{\lambda}_x + \bar{\lambda}_y\right) + a_{Dx}\bar{\lambda}_y}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}$$

$$f = \frac{-a_{Dy}q_{y,\text{RES}}\left(a_{Dx} + a_{Sx}\right) + a_{Sx}\left(a_{Dx}q'_{x,\text{RES}} - \bar{\lambda}_x + \bar{\lambda}_y\right) + a_{Dx}\bar{\lambda}_y}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Sx}a_{Dy}}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}, \frac{\partial q_x}{\partial \Delta K} = 0$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\text{RES}}} = 1 + \frac{a_{Sx}a_{Dx}}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}, \frac{\partial q_y}{\partial \Delta K} = 0$$

$$\frac{\partial f}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Sx}a_{Dx}}{a_{Dx}\left(a_{Dy} + a_{Sx}\right) + a_{Dy}a_{Sx}}, \frac{\partial f}{\partial \Delta K} = 0$$

## A.4. Solution for Case 5 - L+G00

$$q_x = \frac{\bar{\lambda}_x - a_{Sx}(-q'_{x,\text{RES}} + K')}{a_{Sx} + a_{Dx}}$$

$$q_y = \frac{\bar{\lambda}_y - a_{Sy}(-q_{y,\text{RES}} - K')}{a_{Sy} + a_{Dy}}$$

$$f = K'$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\mathsf{RES}}} = \frac{a_{Sx}}{a_{Sx}+a_{Dx}}, \frac{\partial q_x}{\partial \Delta K} = \frac{-a_{Sx}}{a_{Sx}+a_{Dx}}$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial q_y}{\partial \Delta K} = \frac{a_{Sy}}{a_{Sy}+a_{Dy}}$$

$$\frac{\partial f}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial f}{\partial \Delta K} = 1$$

## A.5. Solution for Case 6 - L+G10

$$q_x = q'_{x,\mathsf{RES}} - K'$$

$$q_y = \frac{\bar{\lambda}_y - a_{Sy}(-q_{y,\mathsf{RES}} - K')}{a_{Sy}+a_{Dy}}$$

$$f = K'$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\mathsf{RES}}} = 1, \frac{\partial q_x}{\partial \Delta K} = -1$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial q_y}{\partial \Delta K} = \frac{a_{Sy}}{a_{Sy}+a_{Dy}}$$

$$\frac{\partial f}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial f}{\partial \Delta K} = 1$$

## A.6. Solution for Case 7 - L-G00

$$q_x = \frac{\bar{\lambda}_x - a_{Sx}(-q'_{x,\mathsf{RES}} - K')}{a_{Sx}+a_{Dx}}$$

$$q_y = \frac{\bar{\lambda}_y - a_{Sy}(-q_{y,\mathsf{RES}} + K')}{a_{Sy}+a_{Dy}}$$

$$f = -K'$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\mathsf{RES}}} = \frac{a_{Sx}}{a_{Sx}+a_{Dx}}, \frac{\partial q_x}{\partial \Delta K} = \frac{a_{Sx}}{a_{Sx}+a_{Dx}}$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial q_y}{\partial \Delta K} = \frac{-a_{Sy}}{a_{Sy}+a_{Dy}}$$

$$\frac{\partial f}{\partial \Delta q_{x,\mathsf{RES}}} = 0, \frac{\partial f}{\partial \Delta K} = -1$$

## A.7. Solution for Case 8 - L-G01

$$q_x = \frac{\bar{\lambda}_x - a_{Sx}(-q'_{x,\text{RES}} - K')}{a_{Sx} + a_{Dx}}$$

$$q_y = q_{y,\text{RES}} + K'$$

$$f = -K'$$

$$\frac{\partial q_x}{\partial \Delta q_{x,\text{RES}}} = \frac{a_{Sx}}{a_{Sx} + a_{Dx}}, \frac{\partial q_x}{\partial \Delta K} = \frac{a_{Sx}}{a_{Sx} + a_{Dx}}$$

$$\frac{\partial q_y}{\partial \Delta q_{x,\text{RES}}} = 0, \frac{\partial q_y}{\partial \Delta K} = 1$$

$$\frac{\partial f}{\partial \Delta q_{x,\text{RES}}} = 0, \frac{\partial f}{\partial \Delta K} = -1$$

# B

# Supporting Context

## B.1. The Dutch national context

### B.1.1. Position and role of The Netherlands

Although the full North Sea grid will likely take time to materialize, a group of "friends of the North Sea" can join forces in a number of multilateral projects that will lead by example for the next projects to follow (Meeus, 2025). In turn, a cost-sharing and collaborative investment framework that embodies regional dynamics can be extended to involve other countries from the greater Europe. In this regard, the Netherlands has the potential to establish itself as a path-maker by taking the initiative, given that meaningful benefits can be achieved at both the national and international levels.

According to MinKGG (2025), The Netherlands is faced with numerous advantages of expanding and reinforcing existing transmission capacity in the North Sea. These include:

- Robust infrastructure to support increasing demand for decades.
- Strengthened resilience of society and economy against geopolitical power struggles.
- Prevention of a more costly and vulnerable future reality by not sticking to fossil fuels.

Realization of these benefits is very costly. Rising grid costs will likely create affordability issues for domestic users, especially if these are handled single-handedly. In turn, this will impact The Netherlands' competitive standing internationally and weaken the business case for electrification or undermine the support for it. The Netherlands should advocate for cost-sharing mechanisms between countries and seize the momentum to secure a strategic negotiating position.

A pioneering role is within reach given the country's favorable position: The Netherlands is a net exporter of sustainable electricity. Moreover, several neighboring countries occasionally rely on the Dutch grid for electricity transport without contributing to its costs, which ideally should be addressed through bilateral agreements. These factors position the Netherlands as a strong candidate to lead the region toward more system-level thinking, coordinated planning, and equitable cost contribution (MinKGG, 2025).

### B.1.2. National Energy System Plan (NPE) of The Netherlands

The National Energy System Plan is a road-map for the development of the energy system up to 2050- outlining how The Netherlands plans to achieve their ideal energy system that is sustainable, affordable, and secure (*National Energy System Plan*, 2023). Although the document encompasses a much wider topic than offshore wind expansion in the North Sea alone, a localized perspective on the matter can still be obtained.

According to *National Energy System Plan* (2023), the Dutch government plans to establish collaborative plans on issues related to the energy system in bilateral partnerships with neighboring countries, which potentially include joint development of hubs in the North Sea and agreements on infrastructure development contributing to the overall robustness of the international energy system. Overall, *Key decision 4* of the NPE particularly points out the importance of collaboration on strategic themes and international joint planning of the energy system.

The NPE (2023) is currently being updated with modified goals including offshore wind targets. However, this new version is not expected to be released before the end of the thesis research. As a closing remark, The Netherlands aims to install 30-40 GW of offshore wind in 2040 according to Ministerie van Klimaat en Groene Groei (2025b)- which will likely be re-emphasized in the upcoming update to the NPE.

## B.2. EU regulatory and financing frameworks

### B.2.1. Renewable Energy Directive (RED II and RED III) Cooperation Mechanisms

The RED II framework emphasizes opportunities for cross-border collaboration in renewable energy production, enabling Member States in different geographic regions to benefit from each other's resource profiles (European Commission, 2025b). It establishes three cooperation mechanisms to facilitate such collaboration:

1. <u>Statistical transfers:</u> Without involving any real RES-sourced energy flow between them, countries can engage in an accounting procedure to statistically transfer an amount of renewable energy between them.
2. <u>Joint projects:</u> Two or more EU countries can co-fund a RES project to meet their targets, where the projects do not have to involve physical energy transfer from one country to another. The Commission published their guidance on cost-benefit sharing for RES projects in 2022 to facilitate agreements on mutually beneficial solutions on sharing the costs and benefits.
3. <u>Joint support schemes and opening of national support schemes:</u> Two or more EU countries can co-fund a joint support scheme. This form of cooperation can involve a common feed-in tariff, feed-in premium, or a common quota and certificate trading regime. The same guidance on cost-benefit sharing by the Commission provides information on collaboration via joint support schemes.

As an update to its predecessor, RED III does not fundamentally change the nature of these mechanisms, but it strengthens the role of joint projects by requiring each Member State, by 31 December 2025, to agree to establish a cooperation framework with one or more other Member States for the development of joint renewable energy projects. Within this framework, Member States should aim to realize at least two joint projects by 2030, while Member States with annual electricity consumption above 100 TWh should aim for a third joint project by 2033 (European Parliament, 2023).

### B.2.2. Project of Common Interest (PCI) and Connecting Europe Facility (CEF) Eligibility

Obtaining the Projects of Common Interest (PCI) status for a proposed energy infrastructure project is key for TSOs as it grants access to financing from Connecting Europe Facility (CEF) funds (Butorac, 2026), reducing the share of overall project costs budgeted by them. Article 4 of the TEN-E provides guidance for the conditions to access financing from CEF, although no direct changes have been proposed to these conditions with the Grids Package (European Commission, 2025a).

- The project is necessary for the development of priority energy infrastructure corridors and areas as defined in Annex I.
- The overall benefits of the project exceed its total costs in both the short and long term.
- The project meets at least one of the following conditions:
  - It involves at least two Member States, either directly or indirectly, including through interconnection with a third country.
  - It is located within the territory of a single Member State but has a significant cross-border impact (minimum 10% of project benefits must accrue to the neighboring state).
- For transmission-specific projects, the project significantly contributes to sustainability by:
  - Integrating renewable energy sources into the grid;
  - Transmitting renewable generation to major consumption centers and storage sites;
  - Reducing energy curtailment.
- In addition, transmission projects must contribute to at least one of the following objectives:
  - *Market integration*, including lifting the energy isolation of at least one Member State and reducing energy infrastructure bottlenecks, enhancing competition, interoperability, and system flexibility;
  - *Security of supply*, including improvements in interoperability, system flexibility, cyber-security, appropriate system connections, and secure and reliable system operation.

### B.2.3. EU Grids Package: Articles 15, 16, and 18

This section provides the article-level detail of European Commission (2025e) relevant to cross-border cost-sharing, complementing the summary provided in subsection 2.2.2.

Regarding the CEF funding lines, two are relevant for the meshed North Sea grid: CEF Energy (CEF-E) for cross-border infrastructure and CEF Cross-Border Renewable Energy (CB RES) for cross-border renewable energy projects (European Commission, Directorate-General for Energy, 2025). Gephart (2025) notes that the overall benefit of a cooperation project can only be truly reflected by taking an integrated view on all project components (transmission and generation), and that the current design of the two funding lines is insufficient to accommodate this approach.

The following articles of European Commission (2025e) provide the regulatory direction for cross-border cost allocation:

- **Article 15** addresses the need to develop the grid to accommodate the expected scale-up of offshore renewable energy. Member States are required, within their priority offshore grid corridors, to consider establishing specific cross-border goals for hybrid or cross-border radial projects, with the aim of deploying offshore renewable energy infrastructure in the most regionally efficient manner.
- **Article 16** addresses the assessment and potential revision of guidance on collaborative offshore investment frameworks, including cost-benefit analysis and cost-sharing arrangements for sea-basin offshore network development, with the objective of maintaining a coherent and harmonised approach to offshore grid investment planning and cross-border cost allocation.
- **Article 18** provides the role of project bundling in facilitating cost-sharing discussions between multiple countries. Two or more projects within the same sea-basin can be bundled with a joint cost-benefit analysis, CBCA, and the eventual application for CEF funding.

## B.3. OTC-NSEC direction on designing the next cost-sharing methodology

On 26 March 2026, a workshop on cross-border cost-sharing for generation and transmission investments in the North Sea regional grid was held in Brussels, jointly organized by the OTC and NSEC. The workshop brought together participants from the countries of the Hamburg Declaration, including TSOs represented within the OTC, national energy ministries, and—marking a first for such workshops—national regulatory authorities (NRAs). In addition, representatives from the European Commission and the European Investment Bank were present. This diverse group collectively covers the full spectrum of stakeholders involved in the planning, regulation, and financing of cross-border energy infrastructure.

The workshop aimed to align stakeholders on a practical methodology for fair and implementable cross-border cost-sharing of offshore infrastructure. It focused on identifying the key design dimensions that should guide the development of a regional cost-sharing methodology for the North Sea, with its foundations already established with OTC's Expert Paper IV (Offshore TSO Collaboration (OTC), 2025):

- Both generation and transmission costs should be shared due to closed interlink between the two asset types. However, a clear distinction between asset costs presented in Table 2.2 is suggested. For transmission assets, only CAPEX costs would be shared, with the possibility of ex-post adjustment of sharing keys. Generation assets, on the other hand, would be subject to cost-sharing agreements where only the CfD support schemes are shared cross-border.
- Costs of CfDs should be proportionate to their (possible) benefits, so both costs and revenues from them should be shared according to the same keys.
- The cost-sharing methodology must strike a balance between predictability and flexibility. In this context, predictability and flexibility refer to:
  - **Predictability:** Large(r) portion of the allocated costs are based on modeled forecasts, which increases stability of the investment environment. This is also an indicator of robustness, where investment risk is reduced when mechanism is more robust.
  - **Flexibility:** Large(r) portion of the allocated sharing keys are subject to adjustment post-FID, which allow the framework to reflect changing economic and system conditions.
- Other key performance indicators for cost-sharing methodologies are:
  - **Transparency**: Underlying principles and assumptions that are used to obtain the sharing keys should be understood and accepted by all participating countries.

  - **Fairness**: The proportionality of costs allocated to countries to the expected/realized benefits accruing to them from the project sets. It must be clear for the parties involved that the cost-sharing outcome is better for them than without it.

- The revenues of TSOs must adequately reflect the costs and risks of investments.
- Non-hosting countries shall participate in the cost-sharing agreement if their benefits are above a minimum threshold, which is currently 10% of the total benefits created by the project according to European Commission (2025a).

These recommendations are intended to be operationalized through a cost-sharing mechanism that incorporates a combination of the design considerations. Such considerations involve the temporality of benefit assessment (i.e. before vs. post-FID[1]), how the benefits are assessed (modeled predictions vs. observed metrics), scope of costs and benefits involved, and countries to be involved for a given project/project set.

### B.3.1. Temporality of calculation and governance

According to Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC) (2026), an ex-ante and ex-post mixed approach would enable countries to make investment decisions at an early stage, while ensuring a fair allocation of costs based on observable metrics once reliable data becomes available. The uncertainty associated with ex-post adjustments could be mitigated by limiting the period during which such adjustments are applied or by constraining their magnitude. For this, the following governance options concerning ex-post adjustments are presented:

- **Thresholds:** Reopening of the cost sharing keys (that have been locked at FID) should be limited to a predetermined level. In other words, the mismatch between expected benefits and actual benefits should be disregarded if it is below a certain threshold.
- **Triggering events:** Very impactful events that lead to large changes in the ex-ante assumptions must also be defined upfront. Such events would include important developments in the electricity market design that affect how interconnectors are used or black swan events such as energy crises that lead to unprecedented price spikes. It is unclear how such events could be defined upfront or with how much accuracy they could be represented.
- **Frequency:** Predictability of investment outcomes (key performance indicator) can be improved by defining timeframes for ex-post adjustments, in combination with thresholds. For example, deviations from ex-ante assessments would be assessed every 5 years using observable metrics such as import flows or production from the OWF; which are then checked against the *threshold* to merit the adjustment of the ex-ante sharing keys.
- **Adjustment cap:** Share of costs that can be readjusted ex-post, or the volume of ex-post transactions , can be limited to balance flexibility with certainty from ex-ante sharing keys fixed in FID.

### B.3.2. Scope of costs and benefits

It was well acknowledged that the proposed cost-sharing mechanism shall make clear what costs are covered under the sharing agreement, and to what extent they may be adjusted post-FID. Possible elements of costs covered are provided in Table 2.2. Currently, only CAPEX is included in the OTC's scenario-based cost-sharing modeling assignment, where it is indicated this will be the only cost type to be shared across countries within the new framework to be proposed. Countries are given the option to cover DEVEX as well, which is likely more relevant in the case of project-clustering or hybrid projects; however, there is little confidence that inclusion of DEVEX will be a key factor in reaching a CAPEX

[1]FID refers to *final investment decision*.

cost-sharing agreement and/or an FID. Finally, inclusion of OPEX and DEVEX are left as ”optional” and currently remain out-of-scope for the assessments.

Similarly, what benefits are considered as part of CBAs is as crucial because it directly determines how value is measured and allocated. Countries may account for different benefit components if the scope is inconsistent, which will end up misrepresenting certain benefits that can distort investment incentives (Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC), 2026). Thus, a well-defined benefit scope is needed to ensure transparency and practical implementability of cost-sharing frameworks.

Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC) (2026) provide additional details on the indicators of benefits:

- SEW remains to be the primary indicator of benefits.
- Cost allocation should be proportional to the distribution of change in welfare in each country to the welfare created system-wide.
- The producer surplus of the new offshore wind farm should be excluded from the total SEW calculation as the value of wind is captured in the sharing of the CfD.
- Considering observation-based indicators for ex-post adjustments, cost shares should be adjusted (via transfers between countries) through a mechanism based on the relative net imports during a certain observation period (e.g. one year). Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC) (2026) claim this method is straightforward to measure and account for a country's reliance on energy infrastructure built in other countries.
- Non-SEW indicators should be included in cost-sharing arrangements via a fixed fee. This would be a predetermined contribution by all participating countries (more relevant in a regional cost-sharing practice such as a SB-CBS[2]) that reflect the inability to compute/observe at least some of the hard-to-quantify benefits, such as security of supply and energy independence. It is advised to use such indicators within the ex-ante part of the agreement later to be refined through the use of an ex-post mechanism.

During the discussions, the inclusion of a fixed fee for non-SEW benefits was emphasized. Multiple stakeholders indicated that non-SEW benefits should be enough to drive voluntary participation. However, there is a lack of conceptual alignment regarding "voluntary" participation, particularly in relation to non-host countries. While these countries are expected to participate when their benefits are sufficiently high, participation remains voluntary according to European Union (2022). If a project is expected to proceed regardless, it is unclear what incentives would motivate them to contribute to its cost when the benefits of the project would leak to their borders regardless as was shown in chapter 3.

### B.3.3. Scope of projects

Offshore TSO Collaboration (OTC) (2025) makes clear both generation and transmission costs are to be included to reflect their interdependent benefits and provide a transparent basis for negotiations between countries. Clearly put, this involves covering the full investment costs for transmission assets, while the range of covered costs considers governments that jointly act as counterparties to a cross-border CfD. They also highlight that all cost-sharing arrangements must comply with unbundling rules, which dictate separate financing lines for generation and transmission.

In retrospect, there is no explicit definition of the project configurations to which the proposed methodology would apply. Nonetheless, the workshop discussions implicitly point towards a primary focus on hybrid configurations. Extending the methodology to other configurations, such as radial or cross-border radial projects, reveals several limitations. This is somewhat inconsistent, given that the same institutional framework developing

[2]Sea-basin cost-benefit-sharing

these methodologies projects that approximately two-thirds of future offshore wind capacity will be deployed through non-hybrid configurations (Offshore TSO Collaboration (OTC) and North Seas Energy Cooperation (NSEC), 2026). This discrepancy suggests that the proposed approach may have inherent limitations in terms of its wider applicability.

## B.4. Bornholm Energy Island

The Bornholm Energy Island project is a first-of-its-kind hybrid cross-border project with generation and transmission components between Denmark and Germany. When in operation, this project will be the first ever to utilize a cross-border CfD- where the governments of two different countries act as counterparties to the support scheme. TGS 4C Offshore (n.d.) suggests the following financing structure for the project:

- **Transmission:** 50% paid by a German TSO (50 Hertz), and the other half is paid by the Danish TSO (Energinet).
- **Generation:** Germany will bear 70% of the total 20-year CfD cost, while Denmark will assume the remaining 30%. There is a net support ceiling[3] of € 18.6 billion.
- **Distribution:** 100% covered by Denmark. This is the radial connection to the Bornholm island, where the demand is.

It is worth noting that despite being termed a cross-border CfD, the financing structure is entirely ex-ante. The cross-border nature refers solely to two governments acting as counterparties to the generation support scheme, rather than a flow-contingent side payment mechanism. The full allocation of distribution costs to Denmark is consistent with the Offshore TSO Collaboration (OTC) (2025)'s principle that infrastructure serving domestic demand within the host country falls outside the scope of cross-border cost allocation.

[3] maximum financial support allowed under a government grant or tender process for a project.

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