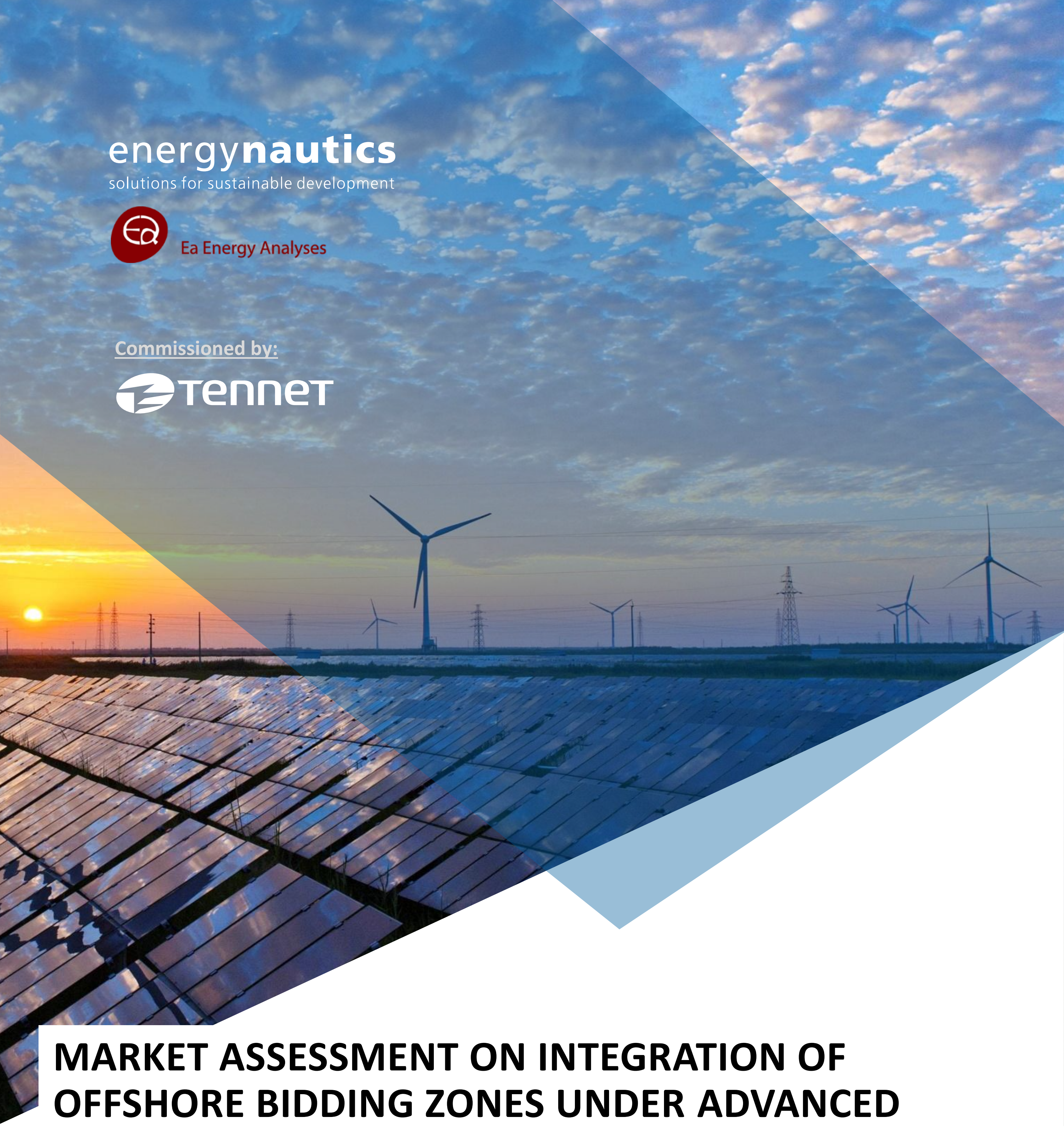

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Ea Energy Analyses

Commissioned by:

TenneT

MARKET ASSESSMENT ON INTEGRATION OF OFFSHORE BIDDING ZONES UNDER ADVANCED HYBRID COUPLING

Quantitative analysis on market value and total system costs

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Preface and Acknowledgements

This report details the outcomes of a technical modelling exercise conducted on behalf of TenneT TSO GmbH. The study represents a joint effort between Ea Analyses and Energynautics, who bear collective responsibility for the methodology and results presented.

The core modelling and analysis were conducted by János Hethey (Ea), Phil Swisher (Ea), and Dr. Andreas Hösl (Energynautics). Modelling support was provided by Raad Alsayyed (Energynautics), with strategic supervision and review by Peter-Philipp Schierhorn (Energynautics).

The authors wish to acknowledge the valuable inputs provided by TenneT TSO GmbH during the consultation phases. However, it should be noted that while the client participated in technical discussions, the findings presented herein reflect the independent analysis of the consortium. EA Analyses and Energynautics stand fully by the integrity of the modelling outcomes.

1 EXECUTIVE SUMMARY

The future transformation of the European power system critically depends on the large-scale deployment of offshore wind. Efficient integration requires rethinking both grid infrastructure and market design. A central component of this discussion is the use of hybrid interconnectors—offshore transmission lines that both connect offshore wind farms and enable cross-border trade.

A key design challenge is determining how to allocate available transmission capacity to maximise socio-economic welfare, while adhering to the physical constraints of the network. European regulation foresees the creation of Offshore Bidding Zones (OBZs), which treat offshore hubs as separate market areas and allocate transmission capacity by means of market coupling. An alternative approach – requiring exemptions to EU regulation – would be the Home Market (HM) model, which integrates offshore wind directly into the onshore markets of the Exclusive Economic Zone (EEZ) in which it is located. The HM model grants wind priority access to transmission capacity. Although the HM model does not fully comply with current regulations, it is often regarded as a benchmark by wind developers because it closely resembles the market access rules of today's radial offshore grid connection systems.

This study compares an OBZ with various HM cases under Flow-Based Market Coupling (FBMC) (including the HVDC interconnectors also referred to as advanced hybrid coupling (AHC)), focusing on the commercial impact for offshore wind farm (OWF) developers and overall system efficiency, including redispatch. The analysis focuses on a specific hub configuration, consisting of a Dutch and German hub, each with 2GW of offshore wind connected, a 2GW connection to its domestic market, and finally a 2GW connection between the two hubs. This is done for the target year 2037. In the first HM case, offshore wind of the respective hubs is integrated into its onshore domestic market with a full exemption from the "70% rule"—a regulatory requirement that reserves 70% of grid capacity for market exchanges. Two further cases explore the impact of limiting or removing this exemption: one case with a partial exemption only for the interconnector cables (referred to as "no onshore exemption"), and one with no exemption.

The results show that OBZ versus the HM cases has significant implications for offshore wind revenues and system costs. For wind developers, the OBZ case generally results in lower market-based revenues compared to the HM case—on average around 10% lower in the modelled cases —because the market price at the offshore hub (almost) converges with the lower of the two connected onshore bidding zones within every hour. Intuitively, the value of wind on the two hubs is equal whenever the hub-to-hub interconnector is not fully loaded (since energy can be transported in between); and with the 2GW sized HVDC elements it is always the hub to shore hybrid interconnectors that are limiting (and can therefore allow a price difference). In contrast, the HM cases allow wind farms to benefit from the potentially higher market price in the assigned home market.

As depicted in Table 1-1, these price effects are **not substantially altered by the use of FBMC** compared to standard hybrid coupling (SHC) (using only NTC for the HVDC interconnectors) - based OBZ case, suggesting that the presence of an OBZ itself — rather than the market coupling methodology — is the primary source of price risk for OWFs. While FBMC introduces additional complexity — such as occasional market-based curtailment, non-intuitive flows and price spreads— its financial impact on wind revenues and overall system costs is limited to about 1% of the total revenue in this study. FBMC effects related to market-based curtailment tend to surface during periods of low prices, when financial stakes are minimal. Price spreads between the hubs and the lower priced onshore market may be regarded as one of the clearest FBMC effects, and would not occur in an SHC setup using NTC for the interconnector cables. These spreads occur in both directions and are, surprisingly, overall leading to slightly higher prices compared to the lower priced onshore markets.

Table 1-1: Observed FBMC effects, their frequency, and their estimated impact on hub revenue

	Number of hours with observed effect (Hours, % of time)	Estimated value (MEUR)	Share of annual revenue (%)
1. Pre-congestion	None	0	**0**
2. Market-based curtailment associated with FB	**95 (1.6%)**	**-0.46**	**-0.06%**
3a. Situations with grid congestion caused by AHC – higher price at hubs	**1096 (12.5%)**	**+7.76**	**0.97%**
3b. Situations with grid congestion caused by AHC – lower price at hubs	**304 (3.5 %)**	**-3.14**	**-0.39%**
4. No full utilization of interconnector	**245 (2.8%)**	**-0.40**	**-0.05%**
Total		**+3.76**	**0.47%**

In terms of volume risk, the OBZ case leads to a slightly higher level of market-based curtailment at the hubs, increasing from 4.3% to 5.8% compared to the HM case. Although available transmission capacity is always sufficient to evacuate the full OWF output, the market does not always clear the full wind potential. This behaviour can be explained by the fact that the overall optimization of socio-economic welfare by the market coupling algorithm favours other – more well-fare generating – flows over dispatching offshore wind. This is typically happening in hours of high renewable infeed and low prices.

The final dispatch is impacted by the OBZ and HM in two steps: The market outcome, and subsequent redispatch measures to ensure grid compatible operations. The final dispatch reveals the lower efficiency of the Home Market cases, showing higher dispatch of especially gas-based generation. While, in HM, integration of hub-based offshore wind is increased in the market simulations and prevails in the final dispatch, other wind and solar as well as low-emission generation (nuclear, biomass & waste, hydro) are reduced to achieve a grid compatible dispatch. The HM case without exemption is most striking: the market dispatch is highly overoptimistic and integrates high volumes of offshore wind (left side of Figure 1), replacing fossil gas. However, the required redispatch amounts overcompensate this by far (right side). However, the first two HM cases (full exemption and partial exemption) show comparatively low changes for all other generation except offshore wind: production at the hubs is increased by around 1.5% (of the generation potential at the hubs). The HM case without exemptions has a more significant impact of close to 9% of the offshore wind potential at the hubs. This leads to increases in system emissions by 0.5 Mton/year, corresponding to 0.180 kg/MWh of offshore wind generation.

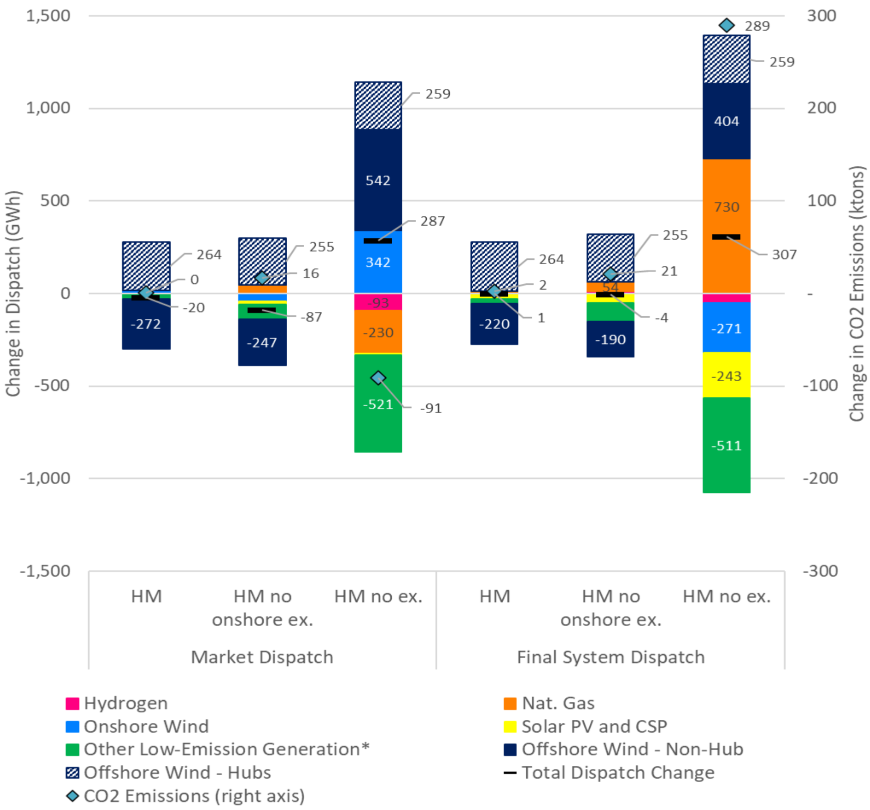

Figure 1: System dispatch changes in HM cases compared to the OBZ. Market Dispatch (left) is compared to Final System Dispatch (right) which includes Redispatch.
**Other Low-Emission Generation* includes Hydro, Nuclear, and Biomass

From a system cost perspective, the performance of the HM case depends heavily on whether it receives an exemption from the 70% rule. With a full exemption, total system costs are only marginally higher than the OBZ case—approximately €2 million per year. However, removing the exemption leads to a situation where both the scheduled generation from offshore wind and cross-border trades might be using the same capacity twice for different purposes. The reason for this is that cross-border trade uses the guaranteed RAM according to the 70% rule, which is not diminished by the transport of the scheduled offshore wind generation. This overloads the offshore grid structure (during 97% of hours) and requires costly redispatch, raising system costs by approximately €93 million per year and increasing dispatch of gas-based units by 730 GWh. Since the study assumes perfect foresight, the redispatch costs of the HM case – whether partially or fully exempted – are expected to be even higher, given the lack of perfect foresight and real-world operational constraints.

Table 1-2: Socioeconomic comparison of HM cases relative to OBZ. MEUR/year.

	HM full exemption		HM no onshore exemption		HM no exemption	
	Total System	Offshore hubs	Total System	Offshore hubs	Total System	Offshore hubs
Producer surplus	84	87	220	92	-183	79
Consumer surplus	-2	-	-164	-	462	-
TSO-Congestion rent	-84	-81	-66	-79	-199	-18
Total market surplus	**-2**	**6**	**-10**	**14**	**80**	**60**
TSO-redispatch cost	0	-	-2	-	172	-
Total system benefit	**-2**	**6**	**-9**	**14**	**-93**	**60**

The impact of market results on stakeholders varies across the cases. The HM case with a full exemption increases OWF revenues while reducing congestion rents accrued by TSOs. Consumer surplus remains largely unchanged. However, removing the onshore exemption alters this balance: system costs rise, producer rents increase due to higher prices, and consumers may face higher electricity costs. Removing all exemptions flips the market balance. The overestimation of market flexibility lowers consumer prices, reduces producer surplus (still positive when only evaluating offshore wind at the hubs) and reduces congestion rents. This direction is explained by the virtually higher interconnector capacity, which would lead to a more flexible market – before redispatch.

A socioeconomic comparison confirms these dynamics: While the HM cases offer higher revenues to wind farm developers and reduce the negative volume effect, they come – especially without exemption for the 70% rule – at a cost of increased redispatch, resulting in overall less total system benefit compared to the OBZ. For the OBZ case, a different distribution between producer surplus to congestion income is observed, which is mainly caused by the introduction of the new bidding zone border, creating an independent price in the OBZ and volume effects for the offshore wind farm.

Conclusion

The lowest system cost and CO_2 emissions occur in the OBZ scenario. It performs best and is the only setup fully compliant with EU regulations.

Compared to a radial setup (represented by the HM case), the OBZ scenario significantly impacts revenue for offshore wind developers—especially those connected to predominantly importing markets. The introduction of AHC/FBMC, however, has a relatively small effect on offshore wind developers by comparison.

Although the findings suggest that HM cases are advantageous for wind developers, the overall negative impact on total system costs outweighs this benefit. A Home Market setup without exemption from the 70% rule should be avoided due to its high system costs.

A Home Market with full exemption from the 70% rule performs similarly to the OBZ setup in terms of overall efficiency and reallocates congestion rents to producer surplus, thereby offering higher revenue for offshore wind developers. However, the study focuses on the day-ahead market and assumes perfect foresight, which may underestimates total operational inefficiencies in an HM setup.

Policy makers must therefore weigh the trade-off between market efficiency and the distribution of economic benefits among stakeholders. Grid strength, flow patterns, and the feasibility of granting regulatory exemptions should all be considered when determining the most appropriate market setup for offshore wind integration.

Disclaimer

The study was conducted for a fictive situation of a hybrid system between Germany and the Netherlands, i.e. two EU Member States already interconnected via AC lines. It should be noted that the conclusions of this study would not necessarily apply to other configurations of hybrid systems. The results of this study depend on several key assumptions. The direction of power flow between Germany and the Netherlands, the strength of the onshore grid, and the application or absence of the 70% rule all strongly influence the outcomes. While the findings are robust within the defined case for the year 2037, alternative configurations could yield different results.

2 INTRODUCTION

Europe's ambitions to decarbonize its energy supply hinge on a substantial expansion of green electricity production—both to replace fossil fuel-based generation and to meet growing demand. As a result, investment in renewable energy is set to accelerate across the continent. Offshore wind, particularly in the North Sea, is expected to play an increasingly vital role in the future European energy system. While the region holds immense potential for offshore wind development, scaling the industry presents considerable challenges that demand technological innovation, economic efficiency, and adaptive regulatory frameworks. Realizing the full societal value of offshore wind will require effective international coordination and strategic, forward-looking planning.

Offshore Bidding Zone and Home Market setup

To improve efficiency and cost-effectiveness, offshore energy hubs have been proposed, connecting large offshore wind farms not only to one onshore market, but also to other offshore energy hubs and to other countries. Thereby the electricity connection from hub to shore will function as a hybrid interconnector enabling both integration of offshore wind and electricity trade. This approach aims to leverage economies of scale and enhances transmission asset utilization. The technology that has emerged as the standard in this context is high-voltage direct current (HVDC). A key advantage lies in the controllability provided by the converters, which can be harnessed in an interconnected system.

However, European regulations on cross-border trades requires there is sufficient capacity on interconnectors for cross-border trade ("70% rule"). This regulation calls for the introduction of offshore bidding zones (OBZ) to efficiently allocate transmission capacity. In this way the actual physical constraints of the interconnectors are considered and thus potential costs of remedial measures can be avoided, which would be needed to otherwise correct infeasible market outcomes. On the other hand, some stakeholders would prefer priority access to transmission capacity for wind farms while using only the remaining capacity for cross-borders trading in order to reduce market risks. This is referred to as the Home Market (HM) setup where offshore wind is guaranteed market remuneration and integration in its respective national bidding zone, as if it would have an exclusive offshore grid connection system similar to radially connected offshore wind.

As offshore wind generation bids at very low marginal costs, it is expected to outcompete non-renewable transmission in most cases. While not formally guaranteed, this effectively ensures that offshore wind can access and sell into the corresponding onshore markets without significant constraints. The potential caveat to this is concerns about onshore congestion preventing wind energy to be transported, or flow based effects.

Flow Based Effects

In an OBZ setup, both price formation and capacity allocation are subject to the outcomes of the market coupling algorithm. Under the traditional Standard Hybrid Coupling (SHC) methods, the available transmission capacity would be given (or be calculated) and serve as a stiff input parameter. The available capacity is offered to the market, independent of the actual market flow from other cross-border trades. Under Advanced Hybrid Coupling (AHC), the available transmission capacities are not only limited by the interconnection capacities but are also influenced by their own and other interconnectors' impacts on onshore grid constraints. This may give raise to flow based effects which may influence the revenue of wind farm developers, and leads to additional potential price and volume risks.

Anticipating some of the results of this study, the following aspects will be discussed:

1. Pre-congestion, where the initial available capacity of the onshore grid is lower than the production potential of the offshore wind farm (OWF).
2. Market-based curtailment of wind at the hubs, although adjacent markets are still above its marginal costs and sufficient interconnector capacity would in principle be available.
3. Price spread caused by flow based effects between hubs and both onshore bidding zones.
4. Price convergence to exporting onshore market (as usual under SHC) but interconnector capacity towards the higher priced onshore market is not fully utilized

Setup of this study

The analysis is based on a simulation of a fictive hybrid interconnector consisting of three 2 GW transmission lines running between Germany and the Netherlands, with two offshore hubs connected in series along the route (Figure 1). Each hub is connected to a 2 GW offshore wind farm. The hybrid interconnector between Germany and the Netherlands serves as a case study, selected primarily due to the availability of detailed grid data. This study aims to provide unbiased insights into market design consequences rather than advocating for any specific infrastructure configuration. The analysis is based on a projected European energy system scenario for the year 2037, characterized by significant transformation compared to today's situation. This scenario, primarily drawn from ENTSO-E's TYNDP Distributed Energy and Germany's Netzentwicklungsplan (NEP), anticipates a system dominated by variable renewable energy sources accounting for approximately 75% of total generation. In particular, the political ambition of the Netherlands and Germany is very high (see Figure 7). This shift substantially influences electricity flows and system dispatch. Electricity demand is expected to rise by roughly 50%, driven by widespread electrification in heating, transportation, and industrial sectors, as well as significant electricity-driven hydrogen production, reaching approximately 13 million tons (433 TWh) annually by 2037.

Content of this study

This study examines both the business case implications for offshore wind farm developers and the impacts on overall system costs and market welfare, including redispatch costs. While wind developers are primarily concerned with market outcomes determined by the market algorithm, a system-wide perspective must also account for redispatch and grid constraints. This study discusses these outcomes separately in subsequent chapters. These results are relevant not only for the business case of offshore wind but also for understanding the broader transition from radial offshore connections to more coordinated offshore grid developments.

To illustrate the impacts on market dispatch and final dispatch, the OBZ case and the HM[1] case are compared, including variants for HM exemptions. The quantitative assessment under different offshore market configurations illustrates the relative impact on the total system.

Concerning flow based effects, a direct comparison between AHC and SHC is not available. The magnitude of flow based effects can however be quantified by investigating marginal price differences and non-intuitive flows as the outcome of the market simulation.

....

[1] The Home Market case assumes that the transmission of offshore wind to the home markets is fully exempt from regulatory minimum capacity requirements (commonly referred to as the '70% rule'). To include the impact of a Home Market setup without full exemption on the 70% rule, sensitivity analyses with limited and no exemption are conducted.

On the backdrop of plans to introduce offshore grids and offshore bidding zone, the current study seeks insights into the following questions:

- What is the price risk for offshore developers induced by an offshore bidding zone setup compared to a simple radial home market situation?
- What is the volume risk for offshore developers induced by an offshore bidding zone setup compared to a simple radial home market situation?
- How are the risks related to Flow-Based Market Coupling?
- What is the impact of the different setup options on other stakeholders and system efficiency?
    - System cost
    - Redispatch cost
    - Impact for producers, consumers and transmission system operators

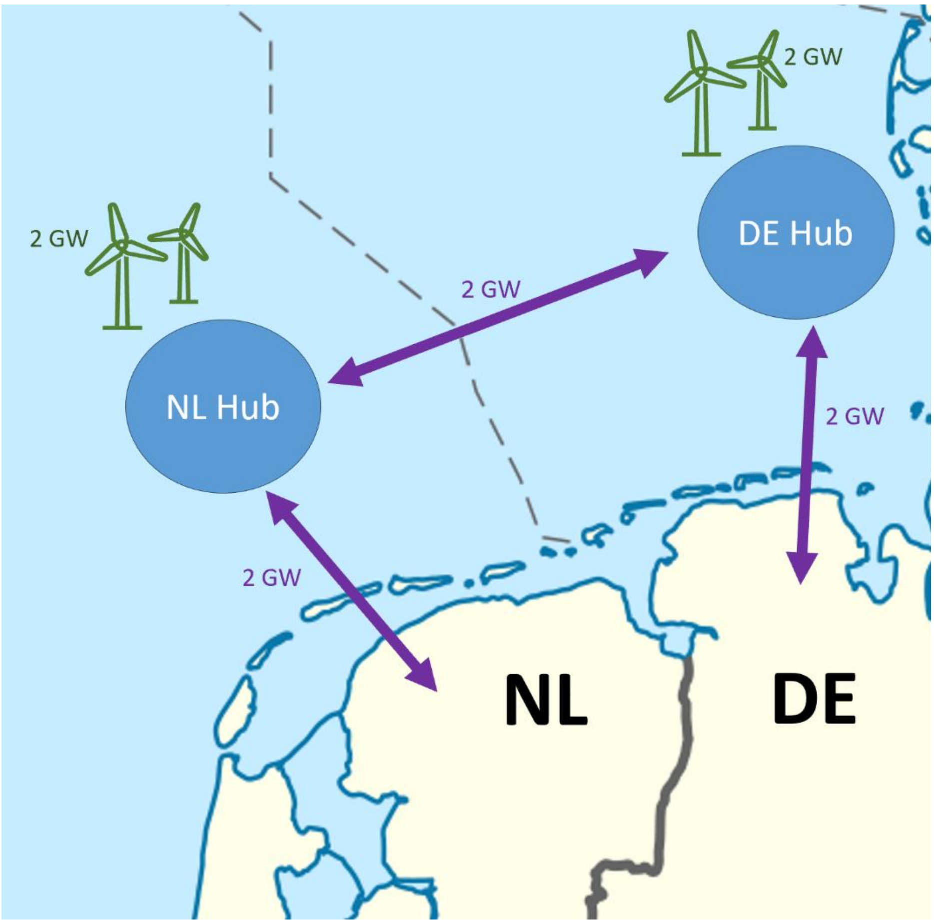

Figure 2: Illustration of the offshore hubs studied in this report

Reader's guide

This report is structured as follows. The executive summary condenses the key concept and findings, while detailed methodological aspects and results are found in the remaining chapters. Chapter 3 introduces the motivation between the different market cases and their sensitivities. The applied system scenario of 2037 is described in chapter 4, detailing market and grid scenario inputs, assumptions and figures. The technical execution of Flow-Based Market Coupling (FBMC) and redispatch modelling follows.

The findings of this study are relevant to two main audiences: (1) OWF developers seeking to understand the commercial implications of the OBZ case under FBMC, and (2) policy makers tasked with choosing between OBZ and HM configurations, including the regulatory treatment of the 70% rule. Chapter 5 analyses the market results and differences between the market setups with focus on the first research question of the study on the implications of OBZ for OWF. Chapter 6 then adds the redispatch results and their differences between the market setups, while chapter 7 combines market and redispatch results to assess the net effect of the market design choices. At the end of chapter 7, the conclusion of the second research question on the implications of OBZ for policy makers is discussed.

Disclaimer:

Various terms exist for describing the used calculation method to determine the capacity on a DC interconnector:

- The Evolved Flow-Based concept is the determination of flow on DC interconnectors within a Flow-Based capacity region.
- Hybrid coupling is a term used for interconnectors that are connected to both Flow-Based and Available Transmission Capacity regions. The capacity on the interconnector can either be defined by a forecasted flow (Standard Hybrid Coupling) or compete with the onshore critical network elements as part of the Flow-Based domain (Advanced Hybrid Coupling).

Note that the used terminology thus depends on the which capacity calculation region the interconnector is part of. Advanced Hybrid Coupling is the term often used in relation to OBZ and the capacity calculation of the hybrid DC interconnector. This term is, however, not fully correct as the OBZ is not necessarily located in a region where the capacity is calculated with Available Transmission Capacity constraints.

To ensure general applicability, the remainder of this report uses both the terms "Flow-Based" and "Advanced Hybrid Coupling" interchangeably for the capacity calculation applied on the interconnectors connected to the OBZ.

3 MARKET SETUP CASES AND SENSITIVITIES

3.1 MARKET SETUP CASES

In order to assess the effects of Hybrid interconnectors with OBZ under FBMC compared to today's radial offshore grid connection systems, the OBZ case is complemented with three HM cases. Each HM case includes the hubs in their respective national bidding zones, as if they were radially connected. The first HM case assumes that the transmission of offshore wind to the home markets is fully exempt from regulatory minimum capacity requirements (commonly referred to as the '70% rule'). To illustrate the impact of a HM case without full exemption on redispatch costs, two further cases, one with limited and one without exemption are conducted and analysed.

Table 3-1: Market setup cases and sensitivities

Case 1: Offshore Bidding Zone (OBZ)	Both hubs in question are placed in their own respective bidding zone
Case 2: Home Market (HM)	Both hubs in question are virtually placed in their respective home market. Capacity on HVDC-lines to shore is reduced with offshore generation potential. RAM of onshore CNECs is reserved *after* application of the 70% rule to account for the impact of the physical flow from the hubs to the onshore grid. **Both HVDC lines and onshore CNECs are exempt from the 70% rule with respect to the impact of offshore wind infeed from the hubs on the onshore grid of their respective home market.**
Case 3: *HM no onshore exemptions*	Both hubs in question are virtually placed in their respective home market. Capacity on HVDC-lines to shore is reduced with offshore generation potential. RAM on system CNECs is considered *before* application of the 70% rule to account for physical flow from the hubs to the onshore grid like any other internal flow, such that the home market setup does not reduce the RAM below 70%. **HVDC lines are exempt from the 70% rule; onshore CNECs are not.**
Case 4: *HM no exemptions*	Both hubs in question are virtually placed in their respective home market. Capacity on HVDC-lines to shore is set to technical capacity. RAM on system CNECs is considered *before* application of the 70% rule to account for physical flow from the hubs to the onshore grid like any other internal flow, such that the home market setup does not reduce the RAM below 70%. **HVDC lines and onshore CNECs are NOT exempted from the 70% rule**

3.2 OFFSHORE BIDDING ZONE SETUP

In the OBZ case, each offshore hub operates as an independent bidding zone, establishing unique pricing mechanisms distinct from the domestic onshore markets. This results in a Dutch OBZ and a German OBZ respectively. Under OBZ, offshore wind generation competes directly within the European market, subject to grid constraints and flow optimizations. This competition introduces two primary risks:

1. Volume risk, where potential onshore grid constraints limit how much energy can be delivered to shore, resulting in additional market-based curtailment of energy; and
2. Price risk, as onshore grid constraints may cause hub prices to diverge from domestic onshore market prices, particularlywhen neighbouring bidding zones exhibit differentprice level.

Other risks related to future developments regarding the overall energy system (e.g. installed RES capacities per bidding zone), grid (i.e. realization grid expansion projects at a certain point in time) and bidding zone setups (e.g. changing bidding zone set-ups of the surrounding / national bidding zones), are not in scope of this study.

Price formation in OBZ

In OBZ under a Standard Hybrid Coupling setup, the expected outcome for price formation is as follows: the price equals the lower of the two connected onshore bidding zone prices due to congestion on the interconnector to the higher priced onshore bidding zone. Intuitively, there must be a congestion: if there was none, more power would flow from the relatively cheap hubs towards the high price zone. As a result, price risk arises primarily in hours when the German and Dutch onshore bidding zones are not price convergent. In such cases, the OBZ linked to the higher-priced domestic bidding zone will face a lower market price compared to the Home Market case.

Under AHC, however, flows from the OBZ to shore compete with other cross-border exchanges for capacity on all critical network elements (that are considered in FBMC) – in particular from the onshore AC grid. This can result in price deviations between the OBZ and the domestic market, even if the DC connection to the domestic market is not fully utilized. Unlike in a SHC setup, the OBZ price under FBMC is not necessarily equal to the lower onshore price. Instead, it can also be below, in between, or even above the prices of the adjacent onshore bidding zones, depending on how the export from the OBZ interact with other exchanges in the Market Coupling via the Flow-Based constraints. This introduces specific Flow-Based effects that are described and assessed in chapter 5.

3.3 HOME MARKET SETUP

For the HM setup, the offshore wind farms are inherently part of the existing onshore bidding zones, ensuring guaranteed access to their domestic markets. As a consequence, flows from generation at the hub to the home market constitute “bidding zone internal flows” that increase the baseline loading of grid elements, thus reducing the transmission capacity for cross-border trade. However, regulatory minimum capacity requirements (commonly referred to as the '70% rule') limit TSOs in taking internal flows into account when calculating cross-border capacity.

The “HM full exemption” (case 2, see Table 3-1) assumes that the transmission capacity of offshore wind to the home markets is fully exempt from the 70% rule. Case 3 and case 4 illustrate the impact of a Home Market case without full exemption on redispatch costs. Case 3 assumes a limited exemption, case 4 a “no exemption”.

Home market with respect to the 70% rule

The 70% rule, introduced under the Electricity Regulation (EU) 2019/943, requires that at least 70% of the capacity of a critical network element (CNE) is made available for cross-zonal electricity trade, regardless of internal flows and loop flows. If allocated flows, internal flows and loop flows together exceed the total capacity, TSOs must manage the resulting congestions through remedial actions, such as redispatch, with associated costs to be borne by the TSO (and consequently tariff payer).

While the export of wind generation from the OBZ is a trade between bidding zones, subject to standard market coupling rules, in the HM setup the transfer of offshore wind generation is an internal flow (HM flow). Thus, in the HM setup, the TSO must provide capacity for both the offshore inflow and the 70% for cross-zonal trade, even if this leads to congestion. This significantly increases redispatch needs and related costs and deteriorates efficient dispatch. To reduce redispatch in the HM setup, offshore flows can be treated as if they were cross-zonal trades. This allows them to count toward meeting the 70% target, lowering the remaining margin required. This approach, effectively a 70% rule exemption, is the standard HM case assumed in this study.

While the final decision on the market setup can be made by the member states, any exemption from the 70% rule would have to be granted by the European Commission, which is highly unlikely. In order to give an indication of the implication (i.e. for system costs) of unaligned decisions, two further cases are analysed:

3. HM case 3 “no onshore exemptions”: Exemption only granted for HVDC connections of the hybrid interconnector, where the HM flows count toward the 70% target. However, no exemption for critical network elements of the onshore grid. TSO must make 70% of onshore CNE available for market use, despite the HM flows.
4. HM case 4 “no exemptions”: The 70% rule is enforced on both onshore CNECs and offshore HVDC links, without any reservations for HM flows from offshore wind.

These cases highlight trade-offs between market integration of renewables and grid reliability. Each case presents distinct challenges and must be carefully considered in future offshore integration strategies.

4 METHODOLOGY AND SYSTEM CASE

4.1 OVERALL MODELLING PROCESS

Modelling both FBMC and redispatch for every hour of the year in a 2037 EU energy system is a complex process requiring multiple models, all of which require a large amount of input data and methodological assumptions, the most important of these are discussed in this chapter.

Ea Energy Analyses and Energynautics are partnering on this project and are covering different sections of the modelling process. Ea specializes in market and case modelling (steps 1, 2, 5) using the Balmorel market model, while Energynautics focusses on grid modelling, Flow-Based Capacity Calculation and redispatch simulations (steps 3, 4 and 6) using PyPSA as a software.

Table 4-1: Modelling process

Step 1:	Build market case(s)
Step 2:	Simulate NTC market results as forecast proxy (NTC pre-run)
Step 3:	Build grid case
Step 4:	Calculate Flow-Based Capacity parameters (grid model)
Step 5:	Simulate Flow-Based Market Coupling (market model)
Step 6:	Calculate power flow and simulate the redispatch process (grid model)

The joint modelling process starts with building a market case for 2037, followed by an initial market simulation using Net Transfer Capacities (NTC pre-run) in the market model Balmorel, which serves as a proxy for the reference flows needed for capacity calculation performed in the PyPSA grid model. The resulting FBMC parameters are then fed into the Balmorel model to simulate Flow-Based Market Coupling. The corresponding dispatch is subsequently played back into the PyPSA model to perform a nodal redispatch optimization and obtain a secure dispatch. Further details on the methodology and individual modelling steps are provided in the following chapters.

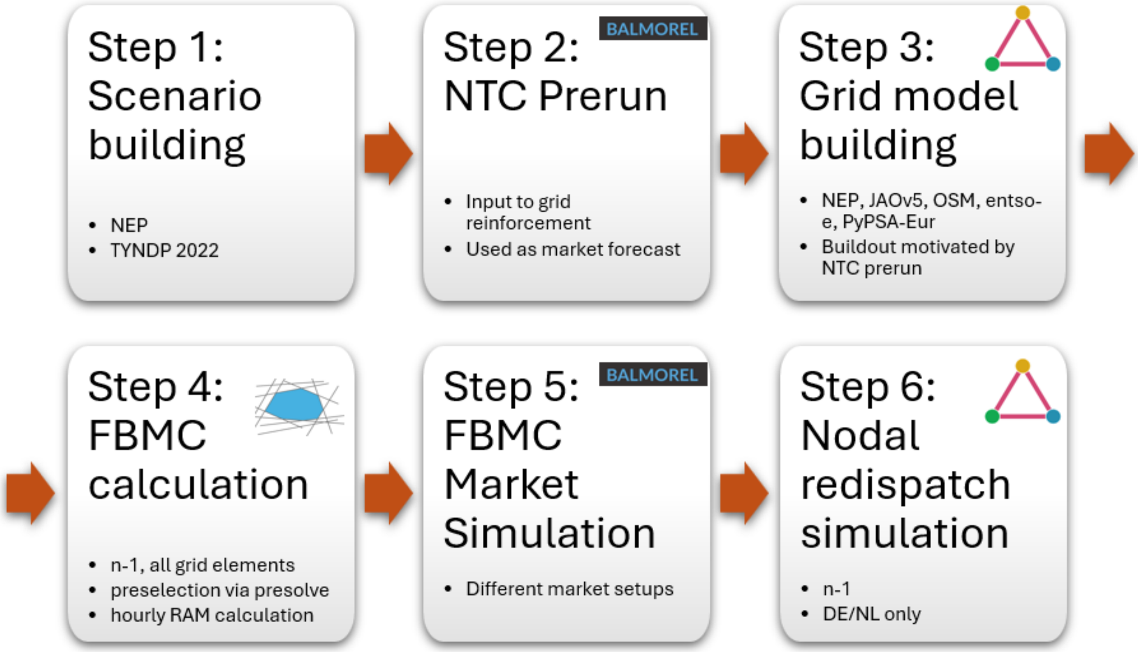

Figure 3: Modelling process: NTC and FBMC market simulations are performed in Balmorel, while FBMC calculation and redispatch are done in PyPSA.

4.2 STEP 1: CASE BUILDING – MARKET

In this study, the EU electricity system of the year 2037 is modelled, where it is assumed significant investment has been made into the supply, transmission, and system flexibility. To model the electricity market, the Balmorel energy market model is used, which is in constant development by Ea Energy Analysis, and has been used by Ea to model energy systems around the world for the last 20 years. With this tool both the electricity and hydrogen system can be modelled during every hour of the year in 31 bidding zones across Europe.

The market model Balmorel is used to estimate the least cost dispatch for the given power system under NTC assumptions (for the NTC pre-run) or Flow-Based Market Coupling (for the market simulation, see section 4.6). This means, that all generation capacities and demand are defined exogenously and the model estimates the dispatch of all power plants taking into account the grid constraints defined by Flow-Based Market Coupling. The resulting dispatch would match the outcome of a market algorithm, provided that all generators bid according to their marginal costs of generation.

The market case defines generation capacities and demand in the different bidding zones. The main sources for those assumptions are the TYNDP2022 and the German NEP 2023. The specific market case is described in the next section.

Energy market case

While this study focuses primarily on the analysis of a German and a Dutch offshore hub, the models used to make this analysis encompass all of Europe, including Norway, the UK and Northern Ireland, and a simplified Balkan region (as a single bidding zone). This is required as changes in trades in one part of Europe can impact flows on the other side of Europe. A map of the modelled bidding zones can be seen in Figure 4.

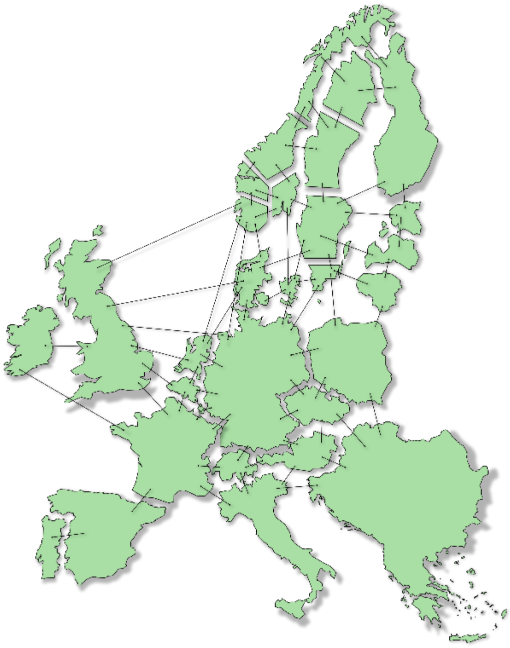

Figure 4: Bidding zones included in the modelled system

There are two references from which the majority of the assumptions used in setting up the market model are taken from. Those references are 1) ENTSO-E's 10-year Network Development Plan (TYNDP) 2022, specifically the Distributed Energy (DE) Cases and 2) Germany's Netzentwicklungsplan (NEP) 2023. The Dutch "Investeringsplan Net op land 2024-2033" was consulted for reference.

The TYNDP 2022 DE case is used to set all the generation capacities and demands for both electricity and hydrogen for the year 2037, linearly interpolating information from the DE 2030 and DE 2040 cases. There is one exception: for all data pertaining to Germany, assumptions are instead based on the NEP 2023, which provides data for the year 2037. The reason is that the political ambition of Germany was updated and features much higher numbers for renewables compared to older figures in TYNDP 2022. In order to achieve comparability to NEP 2023, the newer numbers were used, which are in agreement with TYNDP 2024.

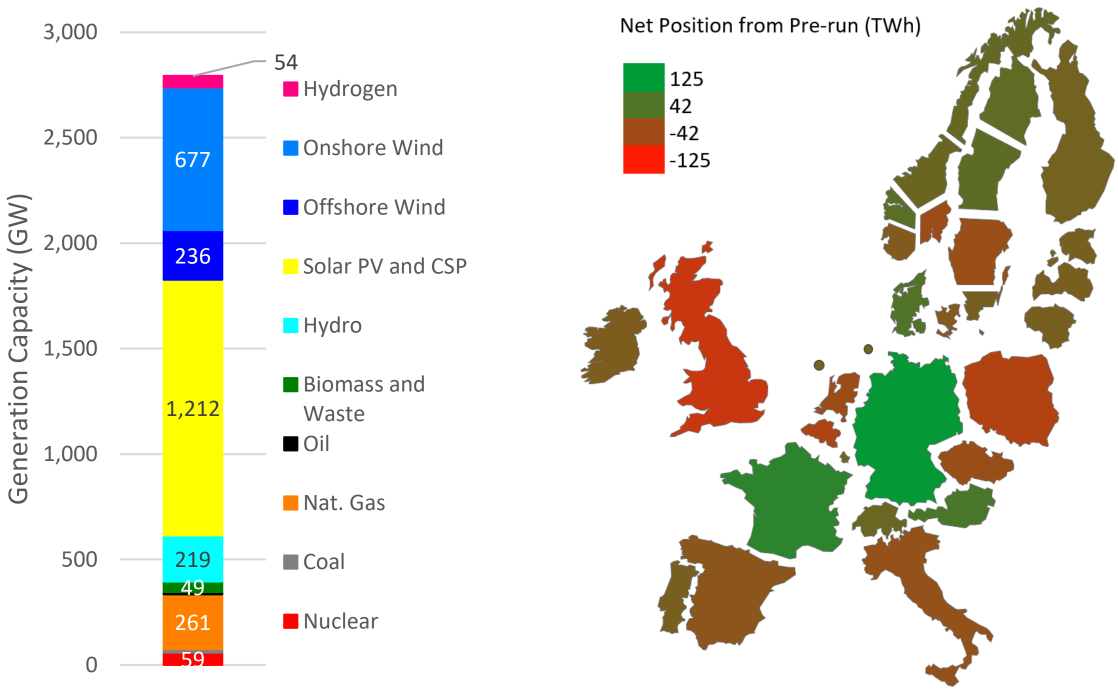

Figure 5: On the left, System wide generation capacity (from NEP 2023 and TYNDP 2022) and on the right, indicative net positions throughout the modelled system from the pre-run

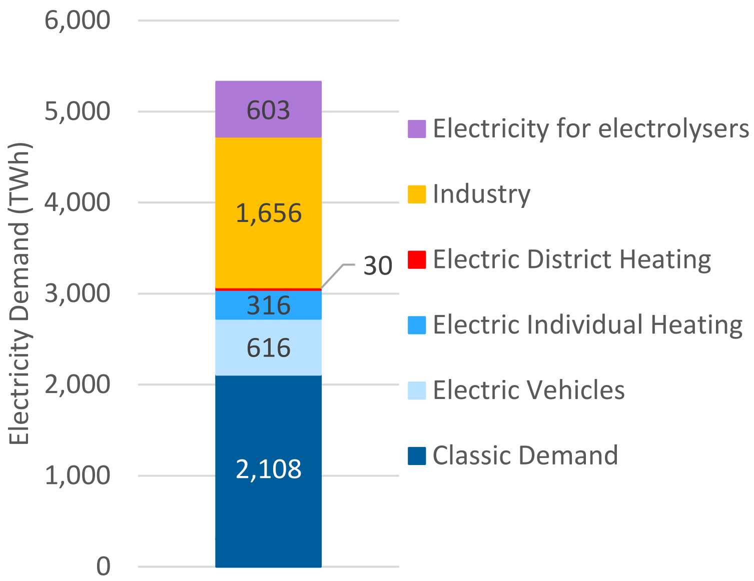

Figure 6: Total electricity demand based on TYNDP 2022's DE cases and NEP 2023.

The resulting assumptions for Germany and the Netherlands can be seen below in Table 4-2. Note that the two hubs in question in this study are included in the total offshore wind capacity for each country.

Table 4-2: Dutch and German power capacity assumed in the model, which comes from TYNDP 2022 (NL) and NEP 2023 (DE)

	Installed Power Capacity (GW)	
	Germany	Netherlands
Nuclear		0.14
Coal		0.3
Nat. Gas	38	29
Oil		0.3
Biomass and Waste	7	2
Hydro	5	0.04
Solar PV and CSP	345	74
Onshore Wind	158	14
Offshore Wind	58	33
Hydrogen Peaker	12	5
Pumped Hydro	11	
Battery	91	21

Cost of energy

Fuel and CO_2 costs are based on the prices stated in Table 4-3, aligned with the German NEP. The price of hydrogen used in electricity generation is set to match the cost of natural gas including CO_2 costs, as hydrogen and natural gas are assumed to be substitutes in gas-fired power plants.

Hydrogen used for power generation is not a part of the hydrogen balance of domestic non-electricity-related demand, domestic hydrogen production from electrolysers and hydrogen imports. The costs to meet hydrogen demand result from the FBMC simulation based on the production options defined in the case setup. Further details on hydrogen modelling can be found in Section 4.2.5.

Table 4-3: Fuel and CO2 price assumptions, based on NEP 2023

Fuel Type	Unit	Price (incl. CO2 tax)
CO2	€/ton	160.5
Gas	€/MWh	19.3 (52.1)
Coal	€/MWh	6.9 (61.8)
Lignite	€/MWh	6.5 (64.9)
Nuclear	€/MWh	1.7 (1.7)
Oil	€/MWh	35.1 (80.2)
Light oil	€/MWh	59.9 (102.6)
Hydrogen for Peakers	€/MWh	52.1 (52.1)

Flexibility in the market model

The 2037 European energy system is much more flexible than today's system, with 603 GWh of utility scale battery storage across the system, and 765 GWh of pumped hydro storage, both of which are shown in Table 4-4. Those assets are assumed to participate fully in market dispatch. Arbitrage between market timeframes (e.g. day-ahead and intraday) is not modelled or assumed to limit operation in the market. Flexibilities are considered in the redispatch step.

Table 4-4: Storage capacity and volume in the modelled system, based on NEP 2023 and TYNDP 2022

	Power Capacity (GW)	Energy Capacity (GWh)
Pumped Hydro	64	765
Batteries	231	603

Batteries are assumed to have an energy to power (E/P) ratio of 3:1 as this is what is assumed in TYNDP 2022, except in Germany, where they are assumed to have an E/P ratio of 2:1, as this is what is assumed in NEP 2023. It should be noted that both sources report power instead of storage capacity when comparing numbers. Pumped hydro on the other hand varies more across the modelled area.

There is demand flexibility present in the market model as well, where it is assumed that 50% of the EV fleet in 2037 has the option to adjust charging patterns based on day-ahead prices. The maximum change is a shift of load by up to four hours, with an hourly maximum charge of 25% of the charge capacity of the price-responsive part of the fleet. Vehicle-to-grid is not assumed. Similarly, heat pumps for individual heating are also responsive to electricity price but are only able to shift load by 2 hours. 3% of "classic" demand is also assumed to behave in a price responsive manner, being able to shift load by 2 hours.

Variable renewable energy sources

Modelling of renewable resources is based on time series for generation provided by the Technical University of Denmark (DTU) for the North Sea Wind Power Hub (NSWPH) Pathway Study 2.0[2], which uses the weather year of 2012.

For onshore wind, each bidding zone has a defined wind potential in different resource grades (RGs), RG A, RG B, and RG C. RG A is a grouping of areas which represent the top 10% of wind areas in a given bidding zone. RG B is then the next best wind areas, representing the next best 40% of the wind resource. Finally, RG C is the bottom 50% of onshore wind areas within a bidding zone. Areas with wind speeds below 5.5 m/s average wind speed are excluded. The utilisation of the different RGs depends on the total wind penetration defined in the case setup and the defined geographical distribution on NUTS1-regions.

For offshore wind, near-to-shore areas (<23 km from shore) are aggregated together, and far-from-shore areas which are 23 or more km from shore are modelled in individual sites, with radial transmission connections to shore. There are also a few offshore hubs where an offshore wind farm is connected to multiple countries. These include the German and Dutch hub, which this report focuses on, as well as the Nautilus (connecting BE and UK), Lionlink (Connecting NL and UK), and Bornholm Energy Island (connecting DK and DE). The latter three are modelled as OBZs in all cases and sensitivities. Profiles for these sites also come from DTU, who have taken into account engineering wake losses and meso-scale wake losses (which however only take effect at high penetration at the different sites). In the North Sea, existing wind farms are assumed to use the Siemens SWT-4.0-120 (4MW), planned wind farms are assumed to use the MHI-Vestas (8MW) and for future wind farms (beyond 2030) NREL (15MW) is assumed. All North Sea wind farms are assumed to have a power density of 8 MW/km^2.

Generation time series for Solar PV are based on DTU's estimates, matching the same climate conditions as for wind in geography and time. Generation profiles are estimated on a NUTS1-level, for the top 25% of solar resource locations. They are all assumed to face directly south.

Hydrogen System

The international hydrogen system is modelled in a simplified manner to maintain comparability with other studies. Electricity use for electrolysers and the resulting hydrogen production are based on a consistent set of assumptions drawn from case definitions in TYNDP 2022 and NEP 2023.

Electrolyser capacities are defined exogenously according to these case sources. Hydrogen demand for end use is distributed across bidding zones and corresponds to the assumed full-load hours for electrolysers in the reference cases. Electrolysers are required to meet this demand but operate flexibly, optimising their output based on electricity prices. This operational flexibility is enabled—and limited—by hydrogen storage assumptions: each bidding zone is assumed to have storage equivalent to ten days of full-load hydrogen production. Demand for hydrogen is modelled with a flat profile over the entire year, and no transmission of hydrogen between bidding zones is allowed.

To prevent unreasonably high hydrogen production costs, a cap of 105 €/MWh_H_2 is applied to short-term production. When demand cannot be covered at or below this threshold, the remaining hydrogen is assumed to be imported and priced accordingly in the socio-economic evaluation. Hydrogen used for electricity generation is not included in the hydrogen balance; instead, power plants can access hydrogen at a fixed price, which is likewise reflected in the cost assessments.

Hydrogen production is expressed in GWh_H_2, representing the energy content of the produced hydrogen. The conversion from electricity to hydrogen assumes an electrolyser efficiency of 69.1%,

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[2] Pathway Study 2.0, NSWPH 2024, https://northseawindpowerhub.eu/knowledge/pathway-20-study

meaning that producing 1 GWh_H_2 requires approximately 1.45 GWh_el of electricity input. Table 4-5 shows an overview of the Dutch and German H2 assumptions based on NEP and TYNDP's assumptions. More details about the hydrogen system can be found in the Annex A, Table 8-2, including results like electrolyser FLH, H2 production, and H2 import.

Table 4-5: Electrolyser capacity from NEP 2023 and TYNDP 2022 and H2 production from the OBZ case

	Electrolyser Capacity (GW_H_2)	H2 Demand (TWh_H_2)
Germany	18	56
Netherlands	12	85
Total System	110	659

4.3 STEP 2: NTC PRE-RUN (FORECAST PROXY)

The NTC pre-run and FBMC market simulation share the exact same market case assumptions regarding system generation capacities, demand and costs. However, the NTC pre-run is based on simplified transmission constraints, as it only takes into account annual average NTCs between bidding zones. The average annual NTCs are based on both the German NEP (for border of Germany) as well as on the TYNDP2022 System Needs Study (interpolation between 2030 and 2040 values). The resulting NTCs used in the pre-run are illustrated on the map below. The dispatch results of the NTC pre-run are used in the PyPSA grid model to establish estimates of the grid parameters to be used in the FBMC market simulation as further explained in section 4.5.

Table 4-6: NTC Values used in the pre-run

	AT	BE	CH	CZ	DE	DK	FR	GB	NL	NO	PL	SE	BEI	Lion Link	Nautilus	DE Hub	NL Hub
AT			2.1	1.9	8.5												
BE					2		6	1	4.4						3.5		
CH	2.1				6.1		6.9										
CZ	1.9				3						2.8						
DE	8.5	2	6.1	3		6.5	4.8	2.8	8	1.4	2	2	2			2	
DK					7.7			2.4	0.7	2.6		4.9	1.2				
FR		6	6.9		4.8			8.8									
GB		1			2.8	2.4	8.8		1	2.8				1.8	1.4		
NL		4.4			8	0.7		1		0.7				2			2
NO					1.4	2.6		2.8	0.7			4.4					
PL				2.8	2							1.5					
SE					2	4.9				4.4	1.5						
BEI					2	1.2											
LionLink								1.8	2								
Nautilus		3.5						1.4									
DE Hub					2												2
NL Hub									2							2	

4.4 STEP 3: CASE BUILDING – GRID

The grid model is a model developed and maintained by Energynautics which details power lines of the European transmission grid (AC and DC), phase shift transformers, localized power generation as well a distributed generation and load distribution. For the current study, grid assumptions for 2037 are required, combining available data for the existing European grid with plans and assumptions on future buildout.

Existing grid and buildout plans

The base grid is compiled from open data sources, primarily the JAO Static Grid Model v5, the German NEP, Marktstammdatenregister, and the open source PyPSA-Eur model (public full scale European energy model). For countries not covered by the static grid model (notably Scandinavia and South-East Europe), data from PyPSA-Eur—based on the ENTSO-E map and OpenStreetMap—is used.

National development plans are incorporated where available (e.g. NEP for Germany and equivalent sources for the Netherlands). In other regions, a simplified economic optimization is used to extend today's infrastructure toward a 2037-compatible grid. For the North Sea, specific offshore hubs are included in the grid development. These include the German and Dutch hub, which this report focuses on, as well as the Nautilus (connecting BE and UK), Lionlink (Connecting NL and UK), and Bornholm Energy Island (connecting DK and DE).

Renewable and conventional generation, as well as storage, is spatially distributed using the criteria below.

Table 4-7: Localization of assets

Technology	Distribution Logic
PV	Allocated by area; regional profiles (NUTS1) with varying full-load hours applied.
Onshore Wind	Existing capacity scaled up (max 2×); further expansion placed by surface area.
Offshore Wind	German projects based on NEP; others distributed along coastlines.
Batteries	Placed proportionally to PV capacity.
Electrolyzers	Placed proportionally to weighted VRE capacity: 150% offshore wind, 100% onshore wind, 50% PV.
Gas & H_2 units	H_2 units located at maximum distance from the planned hydrogen backbone; gas in low-supply regions.
Hydro	Distributed according to resource potential, near existing plants.

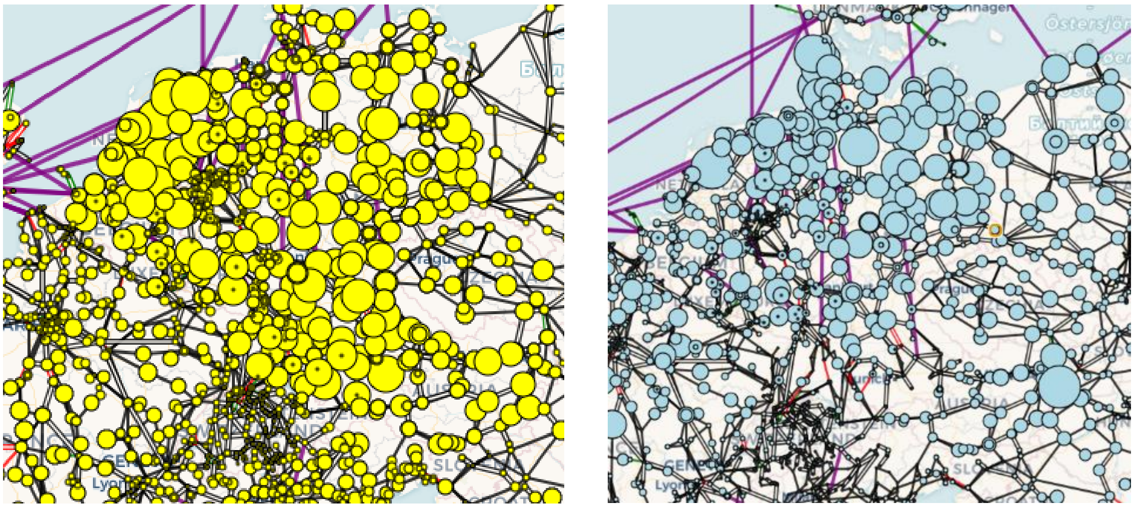

Figure 7: Distribution of solar installations (left) and onshore wind (right). The area of the circles corresponds to the capacity in MWp.

Automated grid buildout

To simulate a realistic expansion strategy, the model applies a rule-based, iterative buildout that mimics a cost-efficient grid reinforcement. To assess grid reinforcement needs, hourly dispatch results from the NTC pre-run are translated into line loadings using a linear (n-1) power flow simulation. For each hour of the year, the contingency that causes the maximum flow on each element is considered. This identifies frequently overloaded components under realistic dispatch conditions.

Based on these results the following iterative reinforcement process is applied:

Table 4-8: Buildout actions

Step	Description
1	Upgrade existing 220 kV lines to 800 MW and 400 kV lines to 2771 MW (4000 A).
2	Add a second 220 kV circuit where only one exists
3	Convert two-circuit 220 kV lines to 400 kV.
4	Add an additional 400 kV circuit on the same corridor

Each reinforcement step is applied only if overloads exceed defined: a maximum of **200%** loading for lines longer than 50 km, and up to **300%** for shorter elements. The process is repeated until violations remain below those thresholds. It should be noted that the NTC pre-run uses a rather simplified representation of grid constraints, so a certain level of overload is acceptable at this stage. This algorithm is applied to Germany, the Netherlands, and surrounding countries covered by the JAO dataset, including Scandinavia and South-East Europe. This provides a consistent basis to estimate reinforcement needs in the context of the studied offshore hub configurations.

Results and Interpretation

Simulation results show that significant grid reinforcement is required to achieve n-1 security in the 2037 case. Most of the necessary buildout comes from upgrading existing lines rather than constructing new infrastructure. In particular, increasing 400 kV line capacities to 4000 A plays a central role. While this is an ambitious target, it is already achieved on select corridors. However, many lines currently report much lower ratings—often below 2000 A—possibly due to conservative estimates, regulatory derating, or inconsistent data quality. The JAO dataset is the only source offering detailed line ratings, and the broad range of values it reports highlights the inherent uncertainty in infrastructure capabilities. The analysis also shows that if all 400 kV lines reached 4000 A, total system capacity (in GW·km) could more than double. Although this is unlikely in practice, it underscores the vast potential of grid modernization.

That said, the high reinforcement volumes are also a product of the top-down case logic: production assets are placed without regard to local grid strength or congestion, operational switching schemes are not modelled, and reinforcement is limited to existing HVAC lines. These simplifications reduce efficiency and likely overestimate the grid investment required—yet they ensure consistent comparability across cases and highlight relative differences in system performance. In particular, a certain comparability to studies using TYNDP transmission values is given by advancing a more detailed grid representation towards those TYNDP scenario targets.

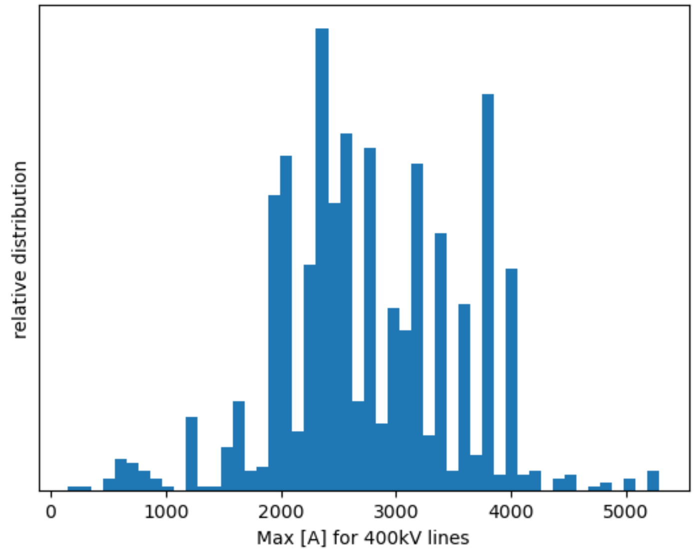

Figure 8: Histogram of maximum allowable amperage on 400kV lines within the JAO static grid model v5

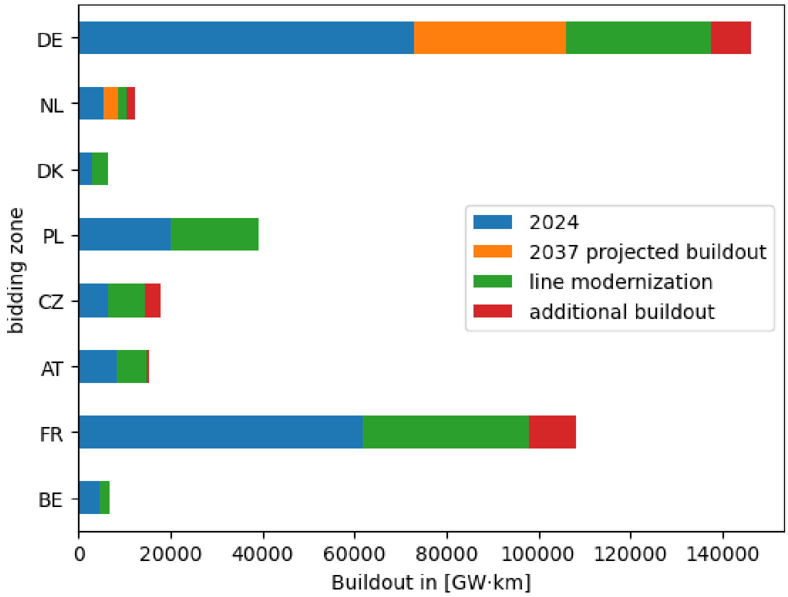

Figure 9: Buildout amounts compared. 2024 shows starting grid. Projected buildout for DE is taken from NEP.

4.5 STEP 4: FLOW-BASED CAPACITY CALCULATION

Flow-Based Methodology

The study applies the Core Flow-Based methodology ("Day-ahead capacity calculation methodology of the Core capacity calculation region," Feb. 2019). Flow-Based constraints are applied to the net positions of bidding zones—variables derived within the market optimization using Critical Network Element with Contingency (CNEC) and Power Transfer Distribution Factors (PTDF). PTDF translate net positions into flows on CNECs, which are subject to a time-varying upper limit: the Remaining Available Margin (RAM). These constraints replace traditional NTC constraints in the market model.

Important terms with regards to the market setup	
OBZ	Offshore bidding zone. Bidding zone established for hybrid offshore hubs, containing generation or load (e.g. offshore wind) and connection to at least two other bidding zones.
HM	Home market. Defining the adjacent main bidding zone of the home country.
CNEC	Critical network element and contingency. Critical network element with a specific contingency (e.g. outage of parallel element) representing an N-1 situation, whose capacity can limit the market solution.
RAM	Remaining available margin. Capacity on a network element made available for cross-zonal exchanges.
PTDF	Power transfer distribution factors. Impact of the change of a bidding zones net position on a critical network element and contingency (CNEC). The difference between the PTDFs of two bidding zones yields the impact of an power exchange between those two bidding zone on the CNEC. A PTDF matrix shows the PTDFs of a number of CNECs and bidding zones.
NTC	Net transfer capacity. Transfer capacity on a bidding zone border made available to the market. Mainly used for defining capacity on interconnectors in the absence of FBMC modelling. However, within FBMC, NTC can also refer to the technical capacity on DC-lines, as those are controllable and DC-lines only limit flows directly by their technical capacity.
70% rule	European legislation, demanding that 70% of the technical capacity of a network element (HVDC-line, CNEC, connection between bidding zones in the case of NTC-modelling) is made available to the market.
Market-based curtailment	The reduction of energy production from renewable sources as a market outcome in case of oversupply or limited export capacities.
(TSO) curtailment	The reduction of energy production from renewable sources as a redispatch measure by Transmission System Operators (**TSO**).

Advanced Hybrid Coupling

HVDC landing points are treated as virtual bidding zones following the Advanced Hybrid Coupling methodology, closely aligned with Evolved Flow-Based (EFB). Although EFB is (as of 2025) only in use on the ALEGrO interconnector (Germany–Belgium), it is expected to be adopted for most future HVDC links. In the simulation, all HVDC lines and Phase-Shifting Transformers (PSTs) apply the EFB logic, meaning they are treated as optimization variables within the market model, allowing the solver to find optimal operating points.

Non-costly Remedial Actions

HVDC lines within a bidding zone (e.g., in Germany) and PSTs are considered primarily as TSO-owned grid assets used for load flow optimization as non-costly remedial actions. However, the market algorithm is allowed to optimize them in the market simulation up to 1/3 of their operational capacity. In this respect, PSTs, in combination with their connecting AC lines, are modelled as partially controllable. Tap positions are linearized, enabling control of flow up to 50% of the line’s capacity. For example, on a 2000 MW line with a 1500 MW flow and a deactivated PST, activation could shift flow to either 500 MW or 2000 MW. The shifted power re-emerges elsewhere as additional flows, but the total transport capacity and operational limits of the lines remain unchanged.

Flow-Based Parameters

Power Transfer Distribution Factors (PTDF)

A single PTDF matrix row is used for the selected CNECs, assuming a fixed grid topology for the entire market year (i.e., no switching, explicit outages, or grid expansion). The contingencies associated to each CNEC, however, implicitly consider outages in line with the n-1 principle.

The nodal PTDF matrix is computed using PyPSA and maps element flows (rows) to nodal injections (columns). For market modelling, it is aggregated into a zonal PTDF matrix, where columns represent bidding zones rather than individual nodes. This zonal PTDF estimates flows resulting from exchanges between zones using Generation Shift Keys (GSKs).

Generation Shift Key (GSK)

The GSK translates nodal to zonal PTDFs by assigning flexible, cost-reflective generators to each bidding zone. Typically, these include gas and pumped hydro units. The model uses a static GSK based on installed capacity shares—dominated by gas, hydrogen, and hydro—which remains constant throughout the year.

The consideration of renewables or electrolysers during oversupply hours (which would make the GSK time-dependent) was deliberately excluded for simplicity and alignment with current practices.

Remaining Available Margin (RAM) Calculation

RAM is computed hourly, following the Core methodology. Starting with the NTC prerun, all bidding zones are initially adapted to a net position of zero, establishing a baseline flow pattern. From the total capacity, 10% is subtracted as the Flow Reliability Margin (FRM). The 70% rule is applied afterward to ensure at least 70% of the element capacity is available for trade.

Additional complexities from other Capacity Calculation Regions (CCR) and NTC links are disregarded as each synchronous area is considered a single CCR (i.e., there are no flows from other CCRs to be considered). The resulting RAM time series is applied in the market simulations.

CNEC Selection and Pre-solving

CNEC represent the grid under an n-1 event to ensure grid stability even under single-element failures. The contingencies are limited to lines and transformers within the model. The potential combinations of critical network elements and contingencies generate an extensive set of approximately 500,000 candidate CNECs, potentially impacting the market dispatch. The number of CNECs is reduced in two sequential steps:

1. **CNE selection:** The model applies a selection according to the Core Capacity Calculation Methodology (article 5.7): elements must have ≥5% sensitivity to zonal trades, and contingencies must result in ≥5% flow impact.
2. **Pre-solving:** A numerical boundary-exploration method is used by sampling random net position vectors within the feasible dispatch space, based on five representative dispatch cases (e.g., high wind, low RES, peak prices, uniform RAM) from the NTC pre-run. Limiting CNECs identified during this process are added to the final set. Numerical convergence is reached when no new CNECs are found.

Final selection of CNECs: 1,427 CNECs for CORE and 410 for the Nordic region.

Technical Representation of the Home Market

In the following, the HM cases are described in comparison to the OBZ setup which serves as a base case. The reason for this is that OBZ follows the methodology of Evolved Flow Based and Advanced Hybrid Coupling for the hub structure with two extra bidding zones and requires no further exemptions or changes to the official FBMC methodology.

Table 4-9: FBMC glossary

F_{MAX}	Maximum technical possible flow per CNEC
F_0	Flow per CNEC in a virtual situation without commercial exchanges
F_{ref}	Flow per CNEC according to forecast, including exchanges
F_{HM}	Flow per CNEC, induced by flows from Hubs to home market
PTDF	n-1 Power Transfer Distribution Function Matrix (bidding zone aggregate)
FRM	Flow reliability margin (safety buffer applied)
NP_{ref}	Net Position per bidding zone per hour according to forecast.
Bidding zone - hub	The net position of the hub is – technically – seen as the net positions of opposing sign of the two virtual bidding zones at the connection points of the hub to shoreline. In the following, “hub” denotes the virtual bidding zone for the onshore connection, and can be regarded as the wind production.

HM cases with partial or full exemption from the 70% rule require consideration of flows from offshore wind generation to the respective Home Markets. In the HM setup, wind generation is virtually included in the onshore zones (Germany/Netherlands), but the hub-to-shore transfer still needs to be considered as reference flow on all CNECs.

$$F_{HM} = Wp * (PTDF_{hub} - PTDF_{onshore})$$

Where F_{HM} is the additional flow on a CNEC caused by importing the full offshore wind potential Wp into the onshore bidding zone. Depending on how the F_{HM} is treated with regard to the 70% rule, the following formulas apply to determine the final RAM.

<u>Without exemption</u>
Without exemption, 70% of capacity must be allocated to the market regardless of the impact:

$$RAM = \max(F_{max} - FRM - F_0 - F_{HM},\ 0.7\ F_{max})$$

where RAM is the remaining available margin, F_{max} the thermal capacity limit of the element, and FRM the flow reliability margin.

<u>With exemption</u>
With exemption from the 70% rule, the allocated RAM for each CNEC is allowed to deviate from the 70% by the flow induced from sending offshore wind generation from the hub to the home market:

$$RAM = \max(F_{max} - FRM - F_0,\ 0.7\ F_{max}) - F_{HM}$$

The exemption may apply only to AC CNECs or also to the HVDC connection of the hybrid interconnector. In the latter case, the simplified formula applies, assuming full controllability of HVDC:

$$RAM_{HVDC} = F_{max} - F_{HM}$$

Flow-Based Constraints and Hybrid Interconnectors

A key consideration is whether Flow-Based constraints could ever block the use of the hybrid interconnector—specifically, whether the RAM on affected CNECs might restrict its full utilization. In the OBZ setup used as the base case in this study, this is **not** the case.

The Maximum Bilateral Exchange (MaxBEx) on the hybrid interconnector – a KPI indicating the magnitude of flow-based capacity – is consistently equal to the technical limit of the HVDC connection (i.e. 2 GW), and this value is never (directly) reduced by Flow-Based constraints. This is possible because the surrounding AC grid at the onshore landing point has sufficient parallel capacity to absorb the full inflow, even under (n-1) contingency conditions. In particular, the direct onshore connection consists of multiple 400 kV double circuits, which—after applying contingency and reliability considerations—still offer more than 2 GW of usable transfer capacity (according to 70% rule).

However, competition for RAM on any CNEC —in particular those not directly at the landing point—may still influence prices in the offshore bidding zones and affect allocated transmission capacity (and thus wind exports).

In contrast, under the HM case with exemptions, offshore wind generation is treated as internal production of the onshore bidding zones. In this case, the resulting flows from hub-to-shore are not subject to FBMC constraints in the market algorithm but still occupy physical grid capacity. As a result, the remaining RAM available for cross-zonal trade over the hybrid interconnector is effectively reduced (according to the respective 70% rule application). This means that in the HM setup, particularly with full exemption, high wind generation will limit the interconnector’s capacity for market-based exchange, resulting in MaxBEx values below 2 GW.

Figure 10: Color-coded (black to bright red) flows for an exchange via the hybrid interconnector.

4.6 STEP 5: FLOW-BASED MARKET COUPLING

The applied market model is originally an NTC coupled system, where the bidding zones are connected via NTC interconnectors. The transition towards a Flow-Based setup requires the following steps:

Table 4-10: Process changing from NTC to FBMC

Step	Description
1	NTC constraints representing grid connection via the AC grid are dropped
2	NTC constraints representing grid connection via HVDC elements are kept
3	Virtual Bidding Zones are added for each HVDC and PST element (c.f. AHC) – (no supply and demand)
4	Flow-Based constraints, formulated in terms of net positions of the bidding zones, are added

Dispatch optimisation can be rerun with the reformulated Flow-Based constraints, thus mimicking the current Day-ahead market. The resulting hourly dispatch for all bidding zones can be evaluated for redispatch needs in the grid model (see following section).

4.7 STEP 6: REDISPATCH

Translating zonal dispatch to nodal grid representation

While in reality the TSO receives production schedules for individual power plants, and load and renewable patterns are derived from (weather) forecasts, the dispatch obtained from the market simulation does not contain unit-level detail but instead aggregates dispatch by energy carrier (e.g., gas, solar) on bidding zone level. Therefore, a distribution of zonal market results to nodal power injections and load at the actual grid level is required and implemented as follows.

For non-renewable units, a random (“marginal cost”) order of units per fuel type is established for each day and remains fixed throughout the modelling process. This order mimics a merit-order dispatch where some units operate at full capacity while others are inactive. Because the order is randomized, the specific units regarded as "cheapest" vary daily, effectively sampling a range of plausible dispatch patterns. It may also reflect planned and forced outages of units. This approach presents a more challenging case for achieving n-1 security compared to a uniform distribution across units.

For each day, the dispatch from the bidding zone is allocated sequentially: starting with the first unit in the random order, each is ramped up to its operational limit until the zone’s dispatch requirement is fulfilled.

Redispatch Methodology

The redispatch step is formulated as a nodal optimal power flow problem aiming to minimize the (pseudo-)cost of achieving an n-1 secure dispatch for each hour. Adjustments to the original dispatch are made at unit level and are subject to operational constraints and artificial costs designed to reflect real-world behaviour and prioritization.

In contrast to the market simulation, the redispatch stage considers all CNECs, including those shielded by the 70% rule in the market run. Redispatch must address both cross-zonal and internal congestion.

CNECs are selected based on a combination of output from the market simulation and a contingency-aware load flow. Only constraints within Germany and the Netherlands — including tie-lines to neighbouring countries — are considered to limit computational complexity.

Redispatch Cost Assumptions and Rules

Because no unified redispatch market exists today, the cost assumptions in this study are stylized and designed to create a plausible and differentiated flexibility response rather than to reflect real-world financials. The artificial costs guide the optimization and define the redispatch priority among units. The following rules apply:

Table 4-11: Redispatch methodology

Technology	Rule
Renewables (PV, Onshore and Offshore wind)	• Redispatch optimisation: Can ramp down at a disincentive cost of 30 €/MWh; additional potential for upward dispatch is not considered. Real cost: Recover variable O&M cost when ramped down
Gas and H_2 units	• Redispatch optimisation and real cost: ○ Ramp-down: recover the market marginal cost minus 20 €/MWh ○ Ramp-up: incur the market marginal cost plus 20 €/MWh
Electrolysers	• Redispatch optimisation and real cost: ○ Ramp-up (consume more electricity): recover the market marginal cost minus 10 €/MWh ○ Ramp-down (consume less electricity): incur the market marginal cost plus 10 €/MWh
Batteries	• Redispatch optimisation and real cost: ○ Can participate if their state-of-charge allows. A maximum of one full-load hour is made available per day. Deviations from the market dispatch are priced at 5 €/MWh and must be rebalanced over the day.
Hydro units	• Are excluded for computational efficiency and due to limited relevance near the hub areas. Gas and electrolyser units are assumed to represent generic flexibility.
Units outside Germany and the Netherlands (cross-border redispatch)	• Redispatch optimisation: Face a penalty of 100 €/MWh to discourage redispatch across borders. However, redispatch between Germany and the Netherlands is performed jointly without penalties. • Real cost: As real cost stated above depending unit.

The lump sums reflect a hierarchy of flexibility: batteries are the cheapest, followed by electrolysers, then gas units. The optimizer can shift production from electrolysers at half the cost of gas units, while batteries provide the lowest-cost balancing option.

Cross-Border Redispatch

A key feature of the redispatch set up is the strong disincentive (100 €/MWh) for cross-border redispatch. Without this penalty, earlier studies showed that the optimizer frequently resolved congestion using large-scale redispatch across (several) bidding zones — a behaviour that does not reflect the assumed institutional setup. The penalty thus reflects the absence of a coordinated Pan-European redispatch market.

Treatment of Infeasibilities

With the described redispatch setup (including renewables curtailment, electrolysers, batteries, and gas units), all but two days of the year could be resolved under n-1 security constraints. These two infeasible days are excluded from subsequent analysis. It is assumed that their omission does not materially affect the main findings but rather signals the need for either more redispatch resources or more relaxed grid security standards in extreme cases.

Redispatch Cost Attribution

Redispatch costs originate from congestion on specific grid elements, but the physical actions required to resolve them may occur in other bidding zones. This is especially relevant in a joint German-Dutch redispatch context. For example, if a gas unit in the Netherlands ramps up to relieve a congestion in Germany, attributing the cost based solely on location would misrepresent the economic driver.

To address this, redispatch costs are attributed using shadow prices from the optimal power flow results each line's dual value (shadow cost) is multiplied by the change in flow to estimate the cost of relieving that congestion. Tie-line redispatch costs are shared between zones. This approach enables a congestion-driven attribution of redispatch cost to bidding zones.

5 FLOW-BASED MARKET RESULTS

This chapter presents the results of the Offshore Bidding Zone (OBZ) case under Flow-Based Market Coupling (FBMC). It then assesses characteristic Flow-Based effects such as non-intuitive flows and compares the OBZ outcomes to three Home Market (HM) cases. While the overall system dispatch and price levels are only marginally affected due to the relatively small size of the two modelled offshore hubs, their market integration and connection setup produce noticeable impacts on dispatch, prices, and economic performance at the hub level.

The chapter includes results related to dispatch changes, financial performance of the hubs, volume risks (e.g. market-based curtailment), and illustrative hourly case studies. While many OBZ results are shown in this section, further system assumptions can be found in the Annex A.

5.1 OBZ CASE RESULTS

Price levels and market value of offshore wind

Average baseload prices in the OBZ case across Europe range from approximately 42 €/MWh in Northern Scandinavia to around 85 €/MWh in the United Kingdom and Ireland (Figure 11). The German and Dutch bidding zones fall in the range of 60 to 70 €/MWh. These prices are primarily shaped by the input case assumptions, such as renewable generation profiles and demand levels. Since the model does not include any form of investment optimisation, the resulting prices should not be interpreted as a long-term market equilibrium.

Germany’s relatively low average prices can be attributed to an assumed renewable generation potential that exceeds domestic demand, resulting in a net export position. Conversely, the Netherlands remains a net importer in this case. The UK, as another significant importer, shows the highest average annual prices.

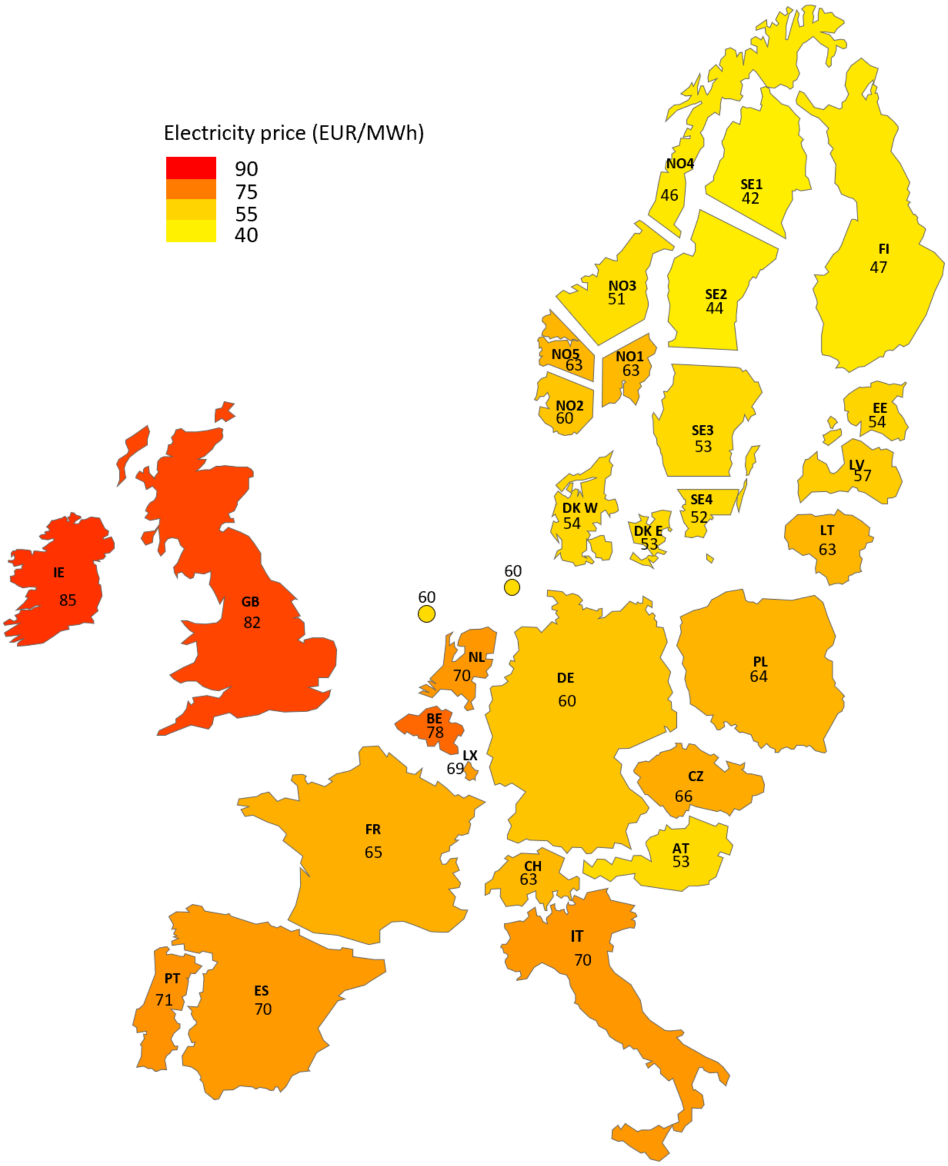

Figure 11: Average electricity prices in the offshore bidding zone (OBZ) case

In Table 5-1, it can be observed that the hourly price convergence between the offshore hubs and their adjacent onshore bidding zones is frequent. For over half of the year (43.3%), all four bidding zones—Germany, the Netherlands, and the two offshore hubs—exhibit prices within 2 €/MWh of each other. In roughly 37% of hours, hub prices are closely aligned with the German market exclusively, which on average tends to be lower than the Dutch market. In contrast, during only 3.5% of hours, the hubs exhibit prices lower than both onshore markets. This situation arises when FBMC constraints limit hub-to-shore flows, effectively preventing price convergence with the onshore markets during low-price conditions.

Table 5-1: Relation of hub and onshore prices in the OBZ case (converged if spreads < 2 €/MWh)

	% of the year this situation occurs	Ave. Hub price during these hours	Ave. DE Price during these hours	Ave. NL Price during these hours
Situation when both hub's electricity prices are:	(%)	(€/MWh)	(€/MWh)	(€/MWh)
-higher than both HMs	0.00%	NA	NA	NA
-lower than both HMs	3.5%	35	41	54
-same as only Dutch BZ	2.6%	114	120	114
-same as only German BZ	37.4%	52	51	67
-All 4 BZ have same price	43.3%	71	71	71
-higher than DE BZ, lower than NL BZ	12.5%	43	39	69
-higher than NL BZ, lower than DE BZ	0.08%	95	93	105

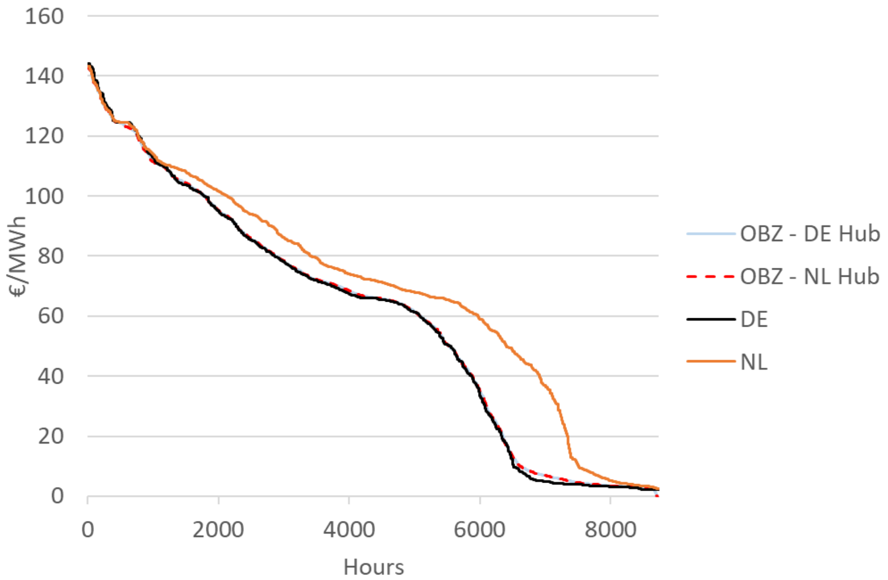

Figure 12: Price duration curve (OBZ-case). Prices are ordered highest to lowest, and thus the same points on the x-axis do not necessarily occur at the same point in time.

Figure 12 and Figure 13 illustrate the price dynamics in the OBZ case. The price duration curve confirms that hub prices follow the lower of the two adjacent bidding zones (which is overwhelmingly DE within this study) in most hours. The histogram of price deviations further supports this, showing that deviations from the lowest of the onshore prices are generally within a narrow ±2€/MWh band. Price deviations from the low price onshore zone can be attributed to FBMC effects, as in system modelled with NTC values on the interconnectors this price deviation would not occur. In these situations, grid constraints across the wider system influence the price at the hubs.

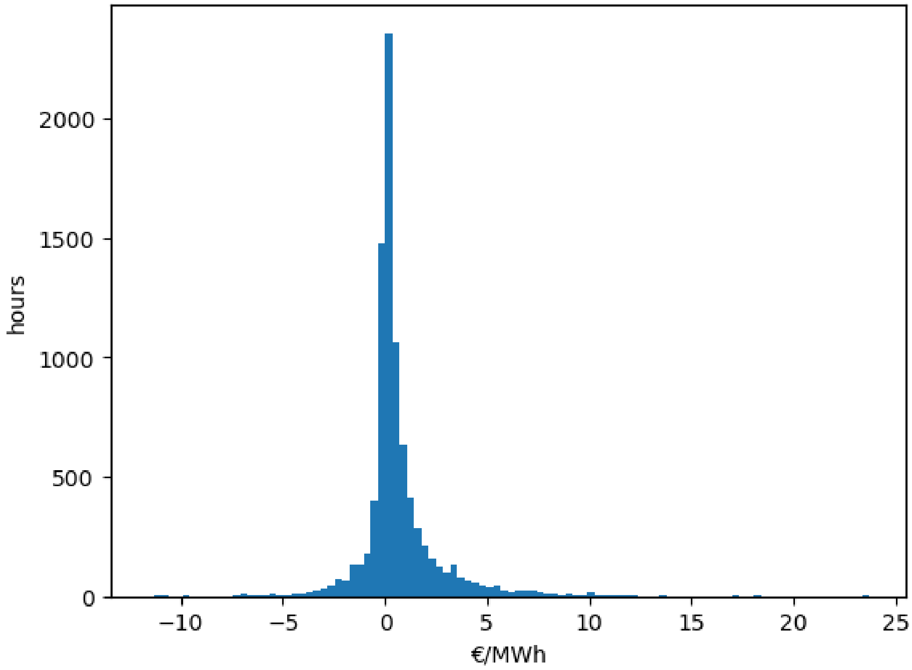

Figure 13: Histogram of the difference between market prices at the hubs and the lower of the two adjacent market zones. Positive values imply higher prices on the hubs. The histogram is identical for both hubs.

Market flows and integration of offshore wind

The OBZ case also reveals the net electricity balances for Germany and the Netherlands. Based on the defined market case, Germany exports a net 127 TWh, while the Netherlands imports 25 TWh annually (Table 5-2). These outcomes reflect assumptions on renewable availability (full load hours) and the geographic distribution of generation.

Table 5-2: Resulting generation and demand in the OBZ case for Germany and the Netherlands

	Total Generation	Generation wind, solar, hydro	Other generation	Total demand	Direct electricity demand	Demand for electrolysis	Net position
	[TWh]	[TWh]	[TWh]	[TWh]	[TWh]	[TWh]	[TWh]
Germany	1089	1032	57	962	887	82	127
Netherlands	264	243	22	289	224	66	-25

Scheduled flows confirm that Germany exports electricity in multiple directions—not only to the south, but also toward neighbouring bidding zones in the north, west and east, as illustrated in Figure 14. This aligns with the country's position as a net exporter with relatively low average prices. The Netherlands, as a net importer, often draws electricity via both its onshore interconnectors and through the hub infrastructure, while it is a net exporter to the UK.

The strong exports of certain countries are foremost rooted in the renewable buildout according to scenario, and secondly depend on weather and full load hour assumptions. Typical fluctuations of 10% of full load hours in between studies can heavily influence the structure of importing and exporting countries.

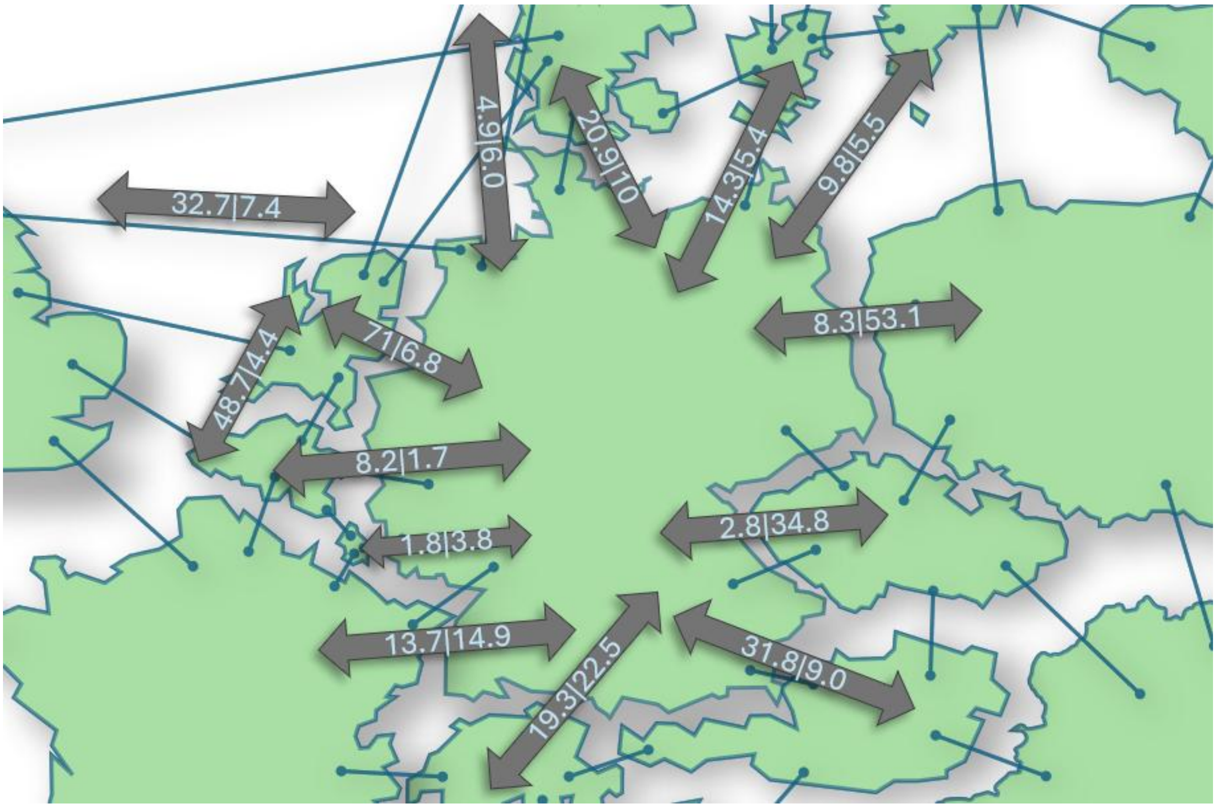

Figure 14: Scheduled market flows aggregated over one year in TWh

Market-based curtailment at the hubs is a relevant volume-related outcome of the OBZ configuration. In total, approximately 1TWh of energy is curtailed by the market at the hubs over the entire the year (Table 5-3). Importantly, market-based curtailment occurs almost exclusively during very low-price hours (below 5 €/MWh), limiting the economic impact.

5.2 ESTIMATION OF FLOW BASED EFFECTS FOR OBZ

As a disclaimer, Standard Hybrid Coupling (SHC) was not simulated within this study, and thus the influence of flow-based effects (as the difference to treating interconnector flows explicitly in AHC) can mainly be understood qualitatively. However, it is possible to estimate the volume of flow-based effects mainly on the revenue of the wind farms and provide a guideline what scale of effect can be expected. An example of non-intuitive flows is presented first, followed by the analysis of different influencing factors.

Examples of non-intuitive flows

The FBMC methodology can lead to non-intuitive flows, i.e., flows from high-price zones to low-price zones, driven by system-wide Flow-Based constraints. These flows emerge because the market algorithm seeks to optimize total system cost by accounting for the impact of all exchanges on CNECs. A non-intuitive flow incurs a cost to the system while at the same time allowing a more cost-effective dispatch elsewhere by reducing load on a limiting element, overall reducing total system cost. The cost remains with the TSOs and reduces the congestion rent earned as summed up over all borders – however, special agreements are in place aimed at redistributing the cost fairly between TSOs.

An example of non-intuitive flows through the hubs occurs in week 38, hour 154. During this hour—a windy and sunny Sunday morning in autumn—the electricity price in the Netherlands is 12 €/MWh, while in Germany it is only 3 €/MWh. Despite this, power flows from the Netherlands to Germany via the hybrid interconnector. This non-intuitive flow reduces congestion on specific CNECs elsewhere in the system, thereby lowering overall system cost. Analysis of shadow prices and PTDFs confirms that the non-intuitive flow relieves congestion on costly elements within this hour. The respective CNECs show high shadow prices and high PTDF factor of the hybrid interconnector.

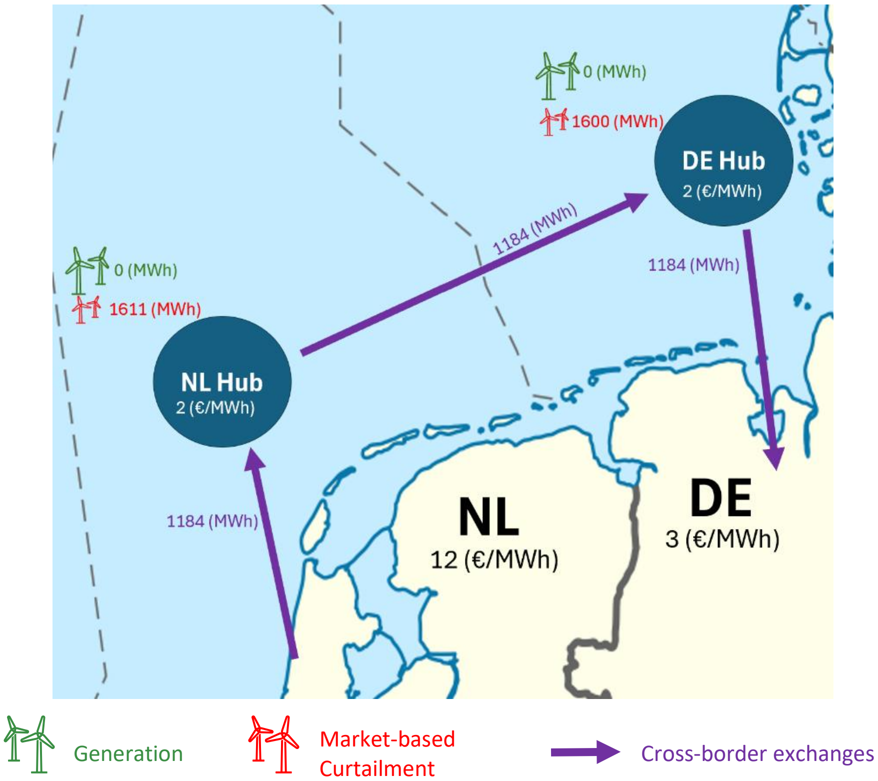

Figure 15: Electricity price and flows around the hubs in question, in the OBZ case during week 38, hour 154

Figure 15 illustrates the flows and dispatch in this particular hour. While such non-intuitive flows are infrequent, they exemplify the systemic optimization inherent in the FBMC methodology and its relevance to offshore hub integration.

Financial and volume impact of flow-based effects for the offshore hubs

The following potential impacts of FBMC are analyzed in the following:

1. **Pre-congestion**, where the initial available capacity on onshore elements is lower than what is needed to transport the full production potential of OWF. The wind production would face trading restrictions, leading to reduced volumes sold and possibly price decay.
2. **Market-based curtailment of wind**, where despite adjacent markets still being above marginal costs of the wind farms, and sufficient interconnector capacity being available, the hub wind is curtailed.
3. AHC leads to **price spreads** between hubs and the lower priced onshore bidding zone:
    a. Price higher at offshore hubs: Indicates that the flow from the hubs to shore has a positive overall impact on grid congestions.
    b. Price lower at offshore hubs: Indicates, that the flow from the hubs to shore has a negative overall impact on grid congestions.
4. Market situations where there is a price difference between two hubs and the onshore markets, but the **interconnector capacity is not fully utilized** to export power towards the higher priced onshore market.

Some of these effects cannot be exactly separated from each other; an attempt is made to estimate upper bounds of volumes and price effects. It should also be noted that the large optimization models are typically solved until convergence under a particular accuracy cutoff, due to runtime limitations.

1) **Pre-congestion** was investigated in 4.5; the conclusion is that due to the 70% rule a bilateral exchange of 2GW of power is always granted. In this study, the hybrid interconnectors feed into substations which are connected to double circuit 400kV HVAC. Even at n-1 security, the available RAM is always sufficient.

However, competition for limited onshore transmission capacity may still influence prices in the offshore bidding zones and affect allocated transmission capacity (see further potential impacts of FBMC below).

2) FBMC effects have the potential to induce **market-based curtailment** of hub production in situations which presumably would not occur or occur at different magnitude in a situation with SHC on the interconnector. This could be the case when the combined impact of the flow from the hubs to the shore and other flows congest a critical network element. In this situation, other flows could be prioritized by the market algorithm, leading to market-based curtailment of offshore wind in the hubs due to FBMC.

Table 5-3: Market-based curtailment in the OBZs

	Number of Hours	Market-based curtailment	% of total Market-based curtailment	Average Hub Price during these hours	Reason
Market-based curtailment during:	[h]	[GWh]	[%]	[€/MWh]	
Price decay both onshore zones: Both onshore zones and both OBZ <5€/MWh	211	635	62%	2.2	Price decay
Price decay one onshore zone: Price convergence of both OBZ with low price onshore zone, price below 5€/MWh in the lower priced zone, and 2GW flow to high price zone	92	159	15%	2.9	Interconnector fully loaded; competition with exporting zone
Non-intuitive Flows: flows from high price zone into low price zone via hub structure	50	156	15%	2.0	Non intuitive flows being prioritized
Other FB effects	45	80	8%	2.4	
Total	398	1031	100%	2.3	

The hours with market-based curtailment are analyzed in Table 5-3. Hours where prices are very low, or where the interconnector towards the high-price market is fully congested (i.e. 2 GW of flow towards the higher price zone), are considered "normal" market-based curtailment, meaning market-based curtailment which would be expected in an SHC system (if non-intuitive flows occur these hours are still counted towards normal market-based curtailment). The market-based curtailment on every other hour – where prices are either clearly above marginal costs of wind at the hubs, or the interconnector is not congested – sums up to 236 GWh. It should be noted that – without dedicated simulation – it is not completely evident how much of that market-based curtailment would occur in a non-flow-based treatment of the hubs (i.e. Standard Hybrid Coupling). As an upper bound, the financial impact can be estimated using the respective market prices of the hubs - this amounts to only 0.457 M€/year. During the hours of non-intuitive flows, half the hours (25) occur when the price spread between the German and Dutch bidding zones is larger than 5 €/MWh (and never above 9 €/MWh) and half when the price spread is below 5 €/MWh and above 2€/MWh (the latter being the threshold used to avoid noise caused by FBMC, as the goal is to highlight meaningful impacts rather than slight deviations in price caused by FBMC).

Overall, flow-based effects may have a relatively strong effect on market-based curtailment volumes since the market-based curtailment order, i.e. competition between different low-cost renewable sources, may be sensitive to small price deviations. Nevertheless, the financial impact purely priced at market value will remain low.

3) **Price spreads** between the hubs and the onshore market that is currently lower in price are a genuine FBMC effect and would not occur in SHC. It indicates that the flow from the hub to the onshore markets has either positive or negative impact on the grid situations leading to a different value of generation at the hubs. We define a price deviation as being present when there is a difference between hub price and the minimum of Germany and Dutch home zone price of more than 2€/MWh. This happens to coincide with the standard deviation of the price deviation. The reason for this cutoff lies in the uncertainty about potential "noise" of the linear model due to limited convergence accuracy. The net effect of the price deviation below 2€/MWh was evaluated separately and is close to neutral (equal amounts positive and negative effect).

Table 5-4 shows that higher prices on the hubs (>2€/MWh) happens ~12.5% of the time, almost exclusively in situations where the hub prices price are higher than the German zone and lower than the Dutch zone, and across the entire year yield an "additional" market value of 7.8 M€/year (compared to the price of the lower priced onshore bidding zone).

FBMC can also lower prices on the hubs and happened ~3.5% of the time in this study. The market value lost amounts to 3.1M€/year, compared again to the price of the lower priced onshore bidding zone.

It should be noted that the exact convergence of prices in SHC is unknown, and these estimates serve as an upper limit estimation of the potential flow-based impact on market-based curtailment. Interestingly, the overall effect appears to favor the value of the offshore wind. The likely explanation is that import flows from the hubs to shore are on average beneficial in terms of grid congestion, as compared to imports from other regions.

4) FBMC-effects can be observed in situations where offshore hub prices align with the lower price onshore market zone, but **without full utilization of the HVDC-capacity** towards the higher priced onshore market. The cost associated with these flows comes with the TSOs since the congestion rent is not fully earned.

However, there is also a secondary pricing effect that affects the business case of the OWF: Even though offshore wind is not curtailed in this situation, a fully maximized flow could increase market prices and thereby market value of offshore wind at the exporting zones. The reason for the presumed increase in market price is that energy produced can be better utilized; and competition between producers in the low-priced onshore zone decreases.

Price spreads with the higher priced onshore market without full utilization of the transmission capacity in that direction happens in 245 hours of the year (Table 5-4). During those hours, wind energy is not dumped, but the flow could have been higher in a situation with an SHC-coupled hub, potentially with a higher electricity price in the exporting region. However, the price elasticity is hard to estimate.

Assuming a relatively high price elasticity of 0.005 €/MWh/MW for illustrative purposes would yield to estimating lost revenue of 0.4 M€/year.[3]

Table 5-4: Observed FBMC effects, their frequency, and their estimated impact on hub revenue

	Number of hours with observed effect (Hours, % of time)	Estimated value (MEUR)	Share of annual revenue (%)
1. Pre-congestion	None	0	**0**
2. Market-based curtailment associated with FB	**95 (1.6%)**	**-0.46**	**-0.06%**
3a. Situations with grid congestion caused by AHC – higher price at hubs	**1096 (12.5%)**	**+7.76**	**0.97%**
3b. Situations with grid congestion caused by AHC – lower price at hubs	**304 (3.5 %)**	**-3.14**	**-0.39%**
4. No full utilization of interconnector	**245 (2.8%)**	**-0.40**	**-0.05%**
Total		**+3.76**	**0.47%**

The total impact of the potential situations is estimated to have very low financial importance for offshore wind, as summarized in the table above.

In total, the FBMC-effects are estimated to **at most 3.76 M€/year or around 0.47%** of the market value of the wind generation at the hubs. Table 5-5 shows further detail into the FBMC effects which are observed in this project.

[3] System calculation indicate a price elasticity 0,0005 €/MWh/MW for increased demand in Germany and 0,0012 €/MWh/h for export reductions, both significantly below the assumed elasticity of 0,005 €/MWh/MW. Thus, even at high price elasticity, the impact of FBMC is estimated to be low.

Table 5-5: Estimation of financial impact of FBMC on offshore wind at the hubs

FB leading to transmission congestion		
Hours of the Year	[h]	297
Average Price Spread between OBZ and BZ	[€/MWh]	7.4
Average Hub Volume	[MW]	1651
Average Flow Reduction	[MW]	395
Elasticity*	[€/MWh/MW]	0.005
Change in Revenue**	[M€]	-0.40
FB leading to market-based curtailment		
Hours of the Year	[h]	95
Annual Volume	[GWh]	236
Average Hub Price	[€/MWh]	2.2
Change in Revenue	[M€]	-0.46
FB leading to increased electricity price (>=2€/MWh) at the hubs		
Hours of the Year	[h]	1096
Annual Hub Volume During These Hours	[GWh]	1807
Change in Revenue	[M€]	7.76
FB leading to decreased electricity price (<=2€/MWh) at the hubs		
Hours of the Year	[h]	304
Annual Hub Volume During These Hours	[GWh]	748
Change in Revenue	[M€]	-3.14
Total Revenue Increase due to FM		
Total Increased Revenue	[M€]	3.76
% of Total Hub Revenue	[%]	0.47%
€/MWh Hub Generation	[€/MWh]	0.22

*Price elasticity is a rough and high assumption for illustrative purposes. System simulations suggest that price elasticity is between 0 and 0.0012 €/MWh/MW

**Change in revenue here is calculated for each hour and then summed up. In each hour the change in revenue is: wind generation * flow reduction * price elasticity

5.3 IMPACT OF HOME MARKET (HM) CASES

Three cases of the Home Market (HM) approach are compared to the OBZ baseline: (1) the standard HM case, (2) a case without onshore CNEC exemptions, and (3) a case with no exemptions at all. These configurations differ in how they reserve grid capacity (RAM) for expected hub-to-shore flows and in how they treat offshore generation in the market model.

Impact on Dispatch and Volume of HM cases

The integration of the hubs into their respective home markets results in a modest increase in the overall volume of energy delivered from the hubs. Compared to OBZ, the first two HM cases result in an increase of approximately 264 GWh in hub energy sales, corresponding to about 1.5% of the total offshore wind generation at the hubs (Figure 16). However, this benefit is offset by increased market-based curtailment of other offshore wind resources elsewhere in the system. The shift leads to a slight rise in thermal generation (mostly hydrogen-based), indicating a somewhat more constrained and costly dispatch outcome relative to the OBZ case. The HM "no exemption" case (case 4) shows a significant reduction of thermal generation with higher cost, thus indicating a less constrained dispatch compared to the OBZ case, which is explained by the additional transmission capacity between Dutch and German bidding zones.

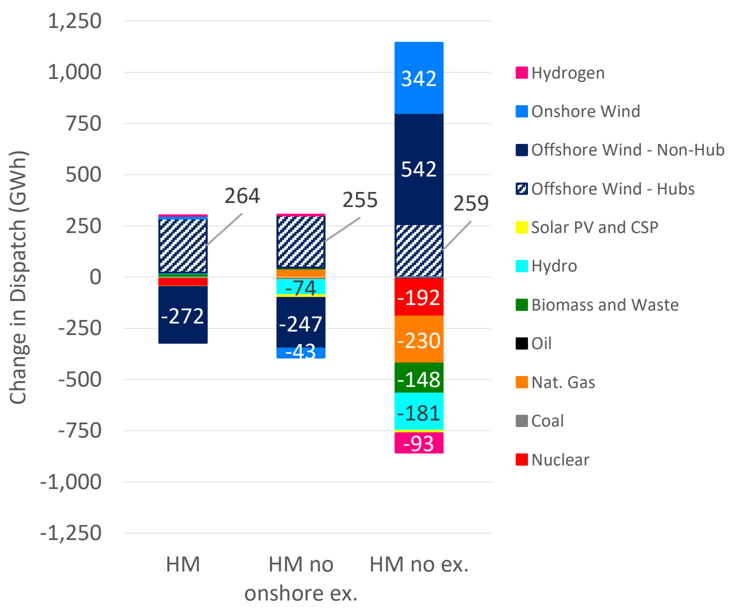

Figure 16: Change in system wide dispatch relative to the OBZ case

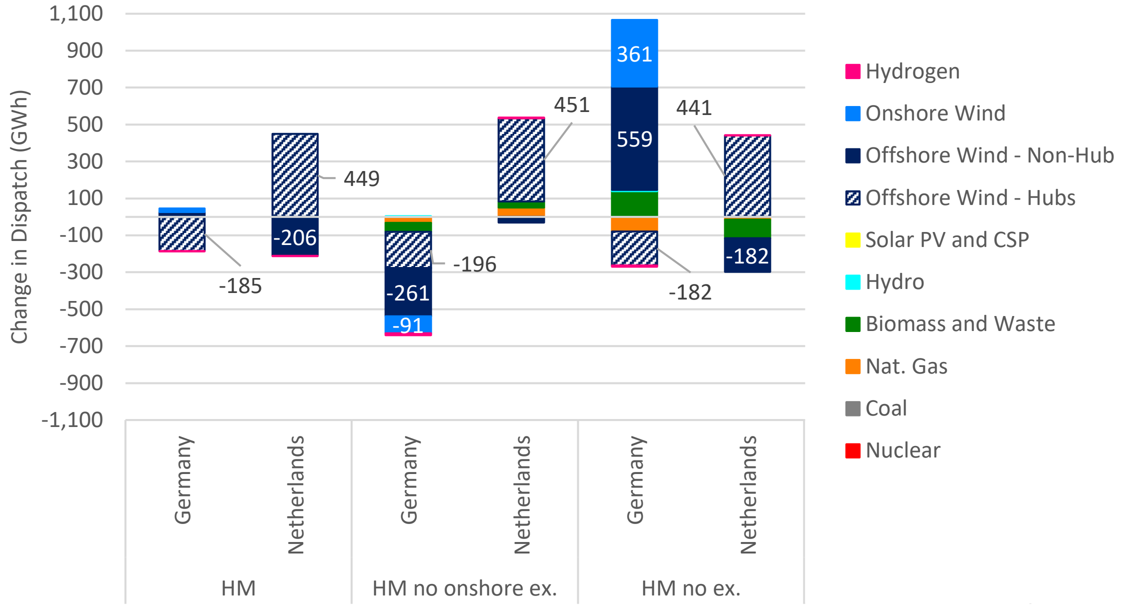

Figure 17: Change in dispatch in Germany and the Netherlands

In the HM cases, the Dutch hub consistently increases its output, while the German hub experiences a reduction in generation. This difference is explained by the underlying price signals in the respective home markets and by the way RAM reservations are applied. In the OBZ case, the market algorithm can dynamically reallocate capacity, whereas in the HM runs, fixed RAM reservations limit flexibility. The HM "no exemption" case (case 4)—where no reservation of the interconnector capacity takes place—results in the largest change in dispatch patterns, allowing for higher imports over the interconnectors but also requiring higher redispatch to manage the physical congestion, which will become apparent when also accounting for the offshore wind flow.

Case studies from individual hours provide further insight. In week 4, hour 8, the Dutch hub dumps more than 1,200 MWh in the OBZ case but none in the HM run (Figure 18). This reflects a situation in which flow to the Dutch market is constrained and hub energy cannot reach consumers. Conversely, in week 8, hour 134, the German hub avoids market-based curtailment in the OBZ case due to system-wide FBMC effects, but experiences full market-based curtailment in the HM case, where the flow's systemic benefit is already assumed and included in the RAM allocation (Figure 19). In this latter situation, the German wind is fully exposed to the oversupply from renewables in the German zone in the HM case. In the OBZ-case, the impact of the flow from German OBZ to the home market and its (in this case beneficial) impact on grid elements is taken into account within the market algorithm, and thus market-based curtailment of energy of other generators in the German bidding zone is preferred.

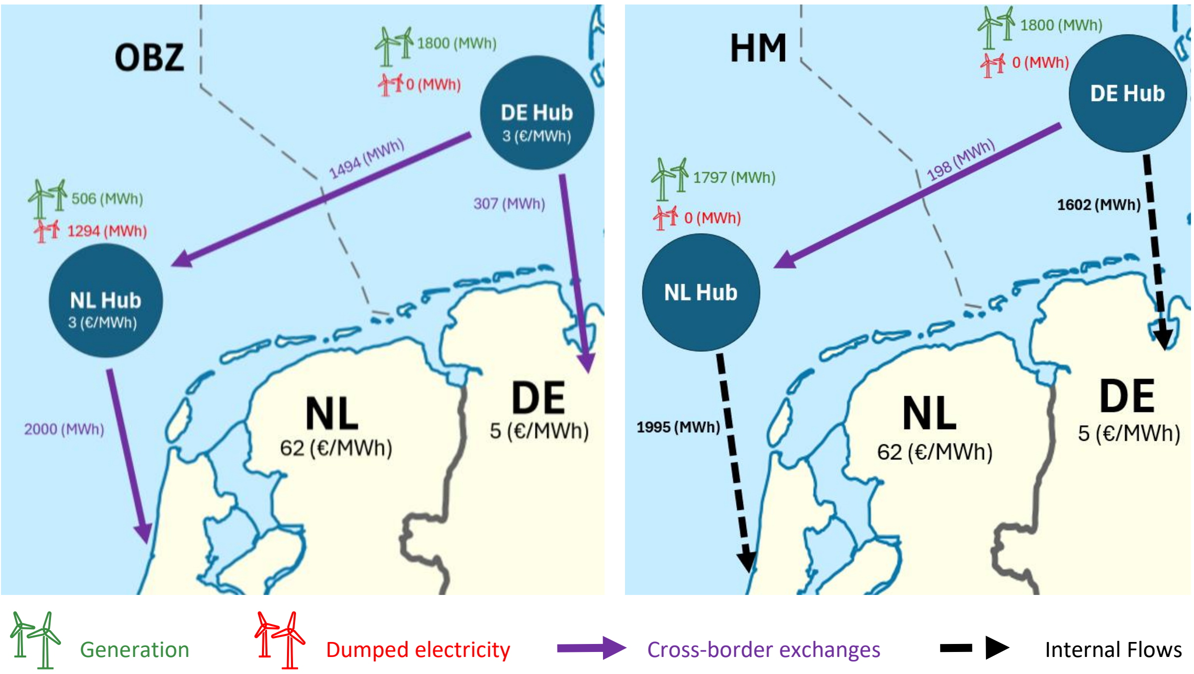

Figure 18: Week 4, hour 8 in OBZ (left) and HM-case (right)

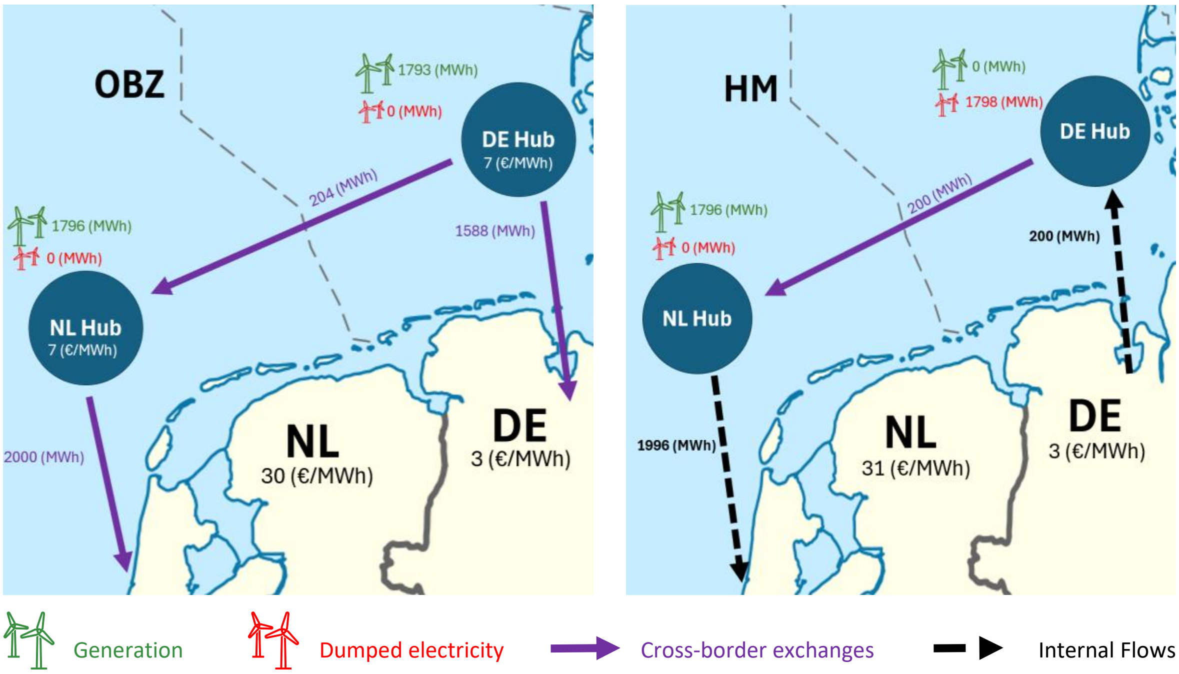

Figure 19: Week 8, hour 134 in the OBZ (left) and HM-case (right)

Market flows and integration of HM cases

The impact of the HM cases on commercial flows (including flows related to offshore wind at the hubs) is relatively minor in most hours. While the distribution of flows around the hubs differs, the net flows—taking into account both hub generation and interconnector usage—are largely similar to the OBZ case. An exception is the HM "no exemption" case (case 4), where the lack of RAM reservations allows for double utilisation of the hybrid interconnectors (up to 4 GW in combined flow). This setup increases market flexibility in the market model but also implies higher redispatch costs to maintain grid feasibility.

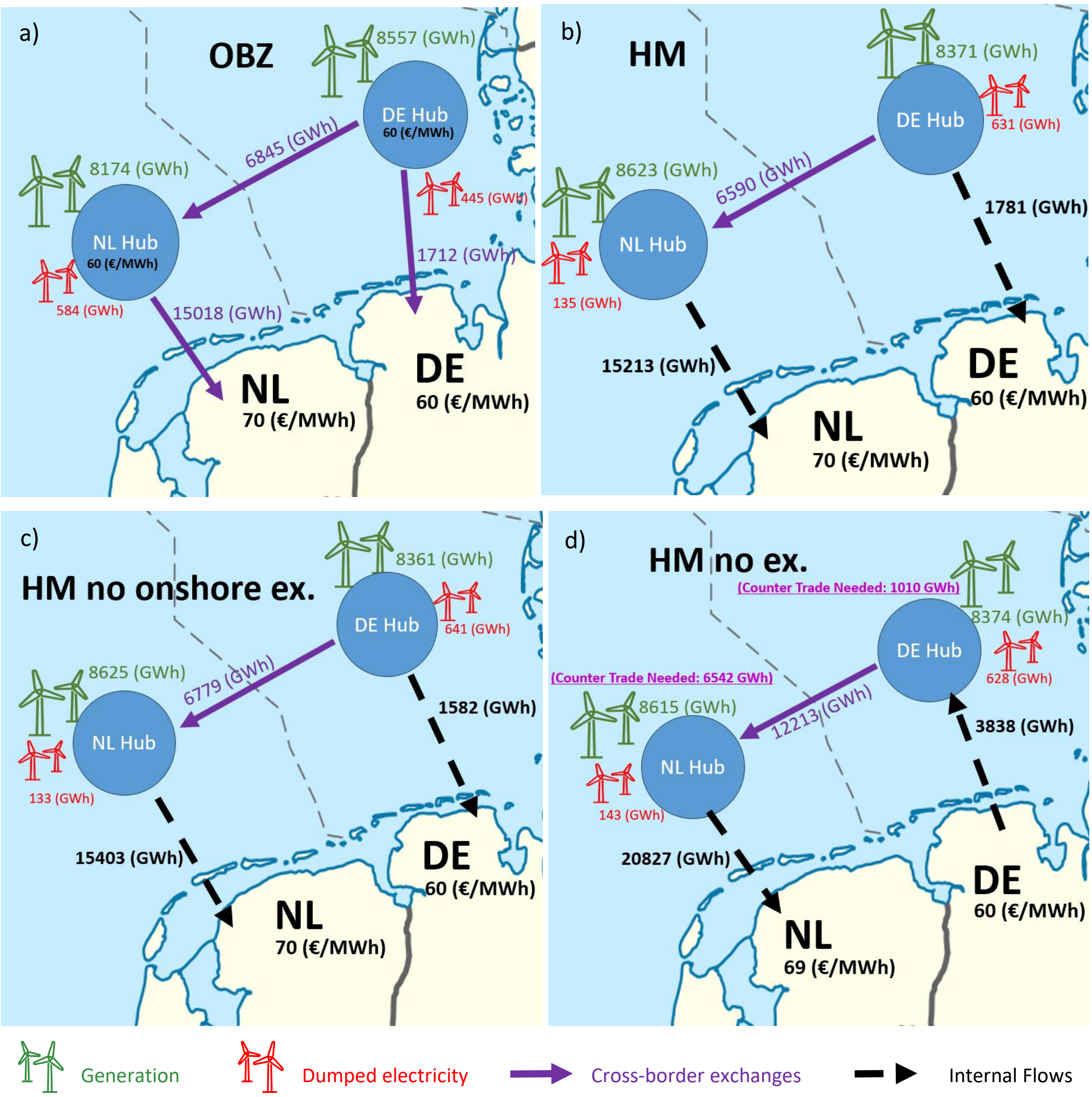

Figure 20: Annual generation, market-based curtailment, and flows in the Dutch and German hubs in each market setup

Figure 20 illustrates annual flow volumes and market-based curtailment at the hubs under each market setup. The results confirm that while the market-clearing outcome shifts, especially in the Dutch hub, the total flow allocation remains relatively stable unless RAM assumptions are altered significantly.

Financial Impact on Hubs

The HM cases affect not only volumes but also the economic performance of the offshore wind hubs. Since the model includes hourly resolution, it is possible to directly compare energy market sales, revenues, and the average market value of electricity scheduled at the hubs across cases.

The Dutch hub benefits substantially from the HM setup. Its energy market sales increase by more than 5%, and total annual revenue rises by approximately 20% to 24% depending on the case. This is primarily due to a higher average market price in the Dutch bidding zone compared to the offshore hub price in the OBZ case. As the offshore wind energy is virtually integrated into a higher-price market, its market value increases accordingly.

In contrast, the German hub sees a slight decrease in sales volume—around 2%—with minimal impact on market-based revenue. While more energy is dumped by the market in the HM runs relative to OBZ, this tends to occur in hours with low system prices. As a result, the overall market revenue impact remains negligible.

Table 5-6: Market value* of wind in the hubs (€/MWh)

	OBZ	HM	HM no onshore ex.	HM no ex.
NL Hub	45.4	55.6	56.3	54.4
German Hub	44.8	44.6	44.6	44.9

*Note: Market value = Annual Revenue/(Annual Generation + Annual Dumping)

Table 5-7: Hub sales volume and revenue (HM model runs are relative to OBZ)

		OBZ	HM	HM no onshore ex.	HM no ex.
German Hub	**Sales volume (GWh)**	8,557	-2.2%	-2.3%	-2.1%
	Revenue (M€)	403	-0.4%	-0.4%	0.2%
Dutch Hub	**Sales volume (GWh)**	8,174	5.5%	5.5%	5.4%
	Revenue (M€)	398	22.4%	23.9%	19.7%
Total	**Sales volume (GWh)**	16,730	1.6%	1.5%	1.5%
	Revenue (M€)	801	11.0%	11.6%	9.9%

Table 5-6 presents the average market value per MWh for each hub across the cases, while Table 5-7 details total sales volumes and revenue. The results demonstrate that the economic importance of the HM case strongly depends on the market price differential between the offshore hub and the adjacent bidding zones. Where the home market consistently has higher prices, the HM case delivers a clear financial benefit to wind farm operators. Where price convergence is already high, the benefits are minimal.

5.4 CONCLUSION ON MARKET RESULTS

The market results focus on solely on the impact on scheduled electricity. The comparative analysis of the OBZ and HM cases under FBMC reveals that the market setup has limited impact on the overall European energy system – as long as exemption from the 70% rule is granted for the hybrid interconnector. Please note that this study provides results with perfect foresight of wind. In practice, the capacity calculation process will be subjected to forecast errors leading to inefficiencies of the use of the cable in the HM case. If no exemption from the 70% rule is granted for the interconnector, shown in cases 3 and 4, the market scheduling is significantly altered towards higher integration of renewables, which will have to be accounted for by redispatch measures. However, all cases have a pronounced effect on the market outcomes and therefore economic prospects of offshore wind farm at the hubs.

Implications for Offshore Wind Farm Developers

OBZ price effect

From the perspective of offshore wind developers, the OBZ case under FBMC introduces a distinct market environment. Prices at the hubs generally converge with the lower of the two adjacent onshore markets. This price effect would also happen in a SHC-based market algorithm and can have significant impact for the offshore wind, in this case placed at the Dutch offshore hub. The market revenue for offshore wind at the Dutch hub is thus around **20% higher in the home market cases** compared to the OBZ case. The reason for the discrepancy between Dutch and German hub is the disequilibrium in renewable buildout in the scenario, with Germany being a large exporter of energy and having lower prices.

The general impact of the OBZ setup is the exposure of offshore wind generation to market prices influenced by both domestic onshore bidding zones. This can be beneficial in systems where dynamic optimization allows for better use of available grid capacity. However, FBMC introduces additional complexity, as prices and dispatch outcomes are no longer determined by simplified interconnector capacity, but rather by the interaction of many grid constraints (CNECs) across the wider system. This means that price formation at the hubs is more volatile and sensitive to remote congestions - anticipation of those effects is more challenging for developers.

Although the OBZ configuration results in higher volumes of curtailed energy by the market compared to the HM case, this occurs primarily during hours with very low prices, limiting the financial impact to about 0.6M€ in this study. The observed market value of offshore wind remains relatively stable, particularly for the German hub, while the Dutch hub sees a more substantial uplift in the HM case due to higher average prices in the Dutch onshore market.

By contrast, the HM setup offers more predictable prices for OWF operators. Offshore generation is virtually placed into a single bidding zone, potentially with higher average prices, and shielded from FBMC-related effects such as non-intuitive flows. If the HM case moves the offshore wind to a primarily importing market (in this case the Dutch home market), this setup significantly improves the market value and revenue of offshore wind. If the home market is a primarily exporting market (In this case the German home market), price convergence between an offshore bidding zone and its home market is already high in the OBZ case, and thus the HM case has low impact[4].

Flow Based Effects

FBMC introduces additional Flow-Based effects, allowing for **non-intuitive flows** and **positive or negative price spreads** between the hubs and shore. These effects are system-driven and not attributable to the local hub generation alone. The price deviation to shore is net positive and yields about 4.5M€ - this suggests that the flows from hub to shore are, on average, easier to integrate compared to imports from other sources such as neighbouring countries. The effects sum up to about **1%** of the total revenue of the wind farms. On the other hand, FBMC introduces volume risks in the form of **market-based curtailment**, particularly at the German hub, although typically during low-price hours. The effect is estimated to about **0.1%** of the expected revenue and results in a net loss. The present study finds that the overall impact of Flow-Based market effects on offshore wind revenues is modest.

....

[4] Depending on the capacity setup of the individual lines of the hybrid connector the impact of a home market setup will change, as the price difference in the OBZ case will change.

6 REDISPATCH RESULTS

Redispatch needs depend on the market outcome and will thus vary depending on the market case. The current chapter illustrates results of the redispatch simulations, starting with the OBZ-case, after which differences induced by the home market cases are explained.

The results are based on perfect foresight, and detailed control over various generation assets. Therefore, the redispatch optimization may underestimate redispatch volumes and prices.

6.1 OBZ CASE RESULTS

Redispatch Volumes

The general tendency for redispatch volumes in the OBZ case is a need to curtail renewables and increase gas-based generation (Figure 21). Total redispatch volumes amount to around 40 TWh up and 40 TWh down, meaning that around 3% of the generation in Germany and the Netherlands needs to be redispatched. Batteries are utilized and feature 5 TWh of shifted consumption and discharge. Electrolysers are used for both up and down regulation, contributing with a net increase in consumption of 3 TWh. Often electrolysers can contribute with a reduction of load (up-regulation) in one are, while increasing load (down-regulation) in another area. Wind and solar power are curtailed with a total of 23 TWh, corresponding to close to 2% of generation in Germany and the Netherlands.

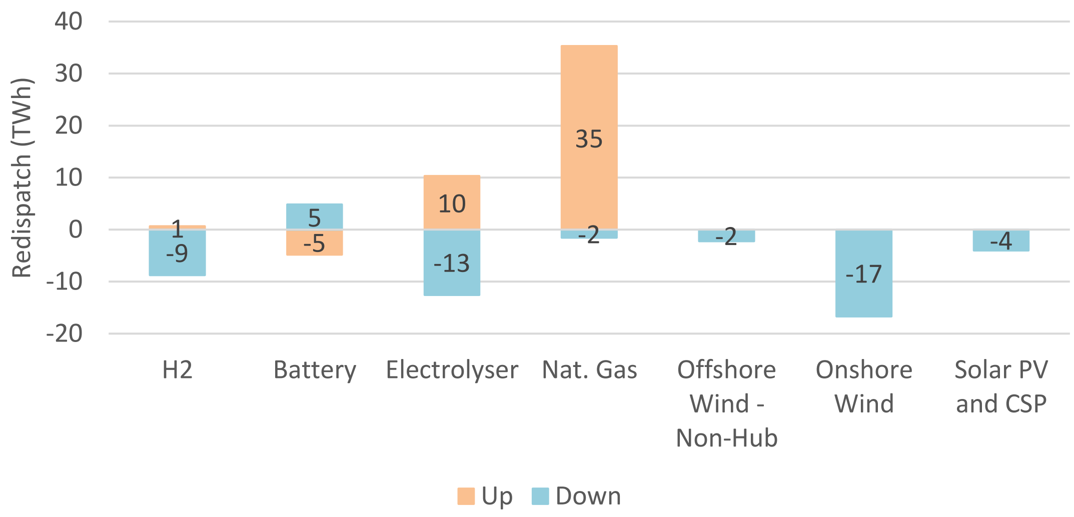

Figure 21: Redispatch volumes in the OBZ-case.

Contrary to other studies[5] volumes and cost (see chapter 7) appear manageable within the chosen case. JRC's study finds redispatch needs of around 12% and 25% of electricity demand in Germany and the Netherlands respectively, while the current study suggests levels of around 3%. The reason is presumably the relatively strong grid reinforcement, and the incorporation of planned Germany-internal HVDC projects. The reservation of two thirds of the phase shift transformers and internal HVDC operational limit may also contribute to the relative stability of the redispatch step: for market purposes, only one third contributes to optimizing trades between bidding zones, while two thirds

....

[5] *Redispatch and Congestion Management*, 2024, ACER-JRC

remain available for redispatch (which does not count into redispatched volumes since no generator outputs need to be adapted).

The influence of battery and electrolyser placement was not investigated, but the favourable location assumptions (joint allocation with renewables) may also be beneficial. Participation of these assets in redispatch services is certainly beneficial and may be economically preferrable to other strategies, but is today not common.

At the same time, the applied assumptions regarding penalties for cross-border redispatch and renewable curtailment are rather conservative. In some situations the cross-border redispatch is however unavoidable (tie line are part of the redispatched lines). Despite the heavy penalty about 7.5% of all redispatch volume (upwards and downwards) occurs via cross-border redispatch. European redispatch market without those penalties would likely be cheaper and lower in volume.

Geographic distribution

The following plot shows the average redispatch positive (red) and negative (blue) at different substations.

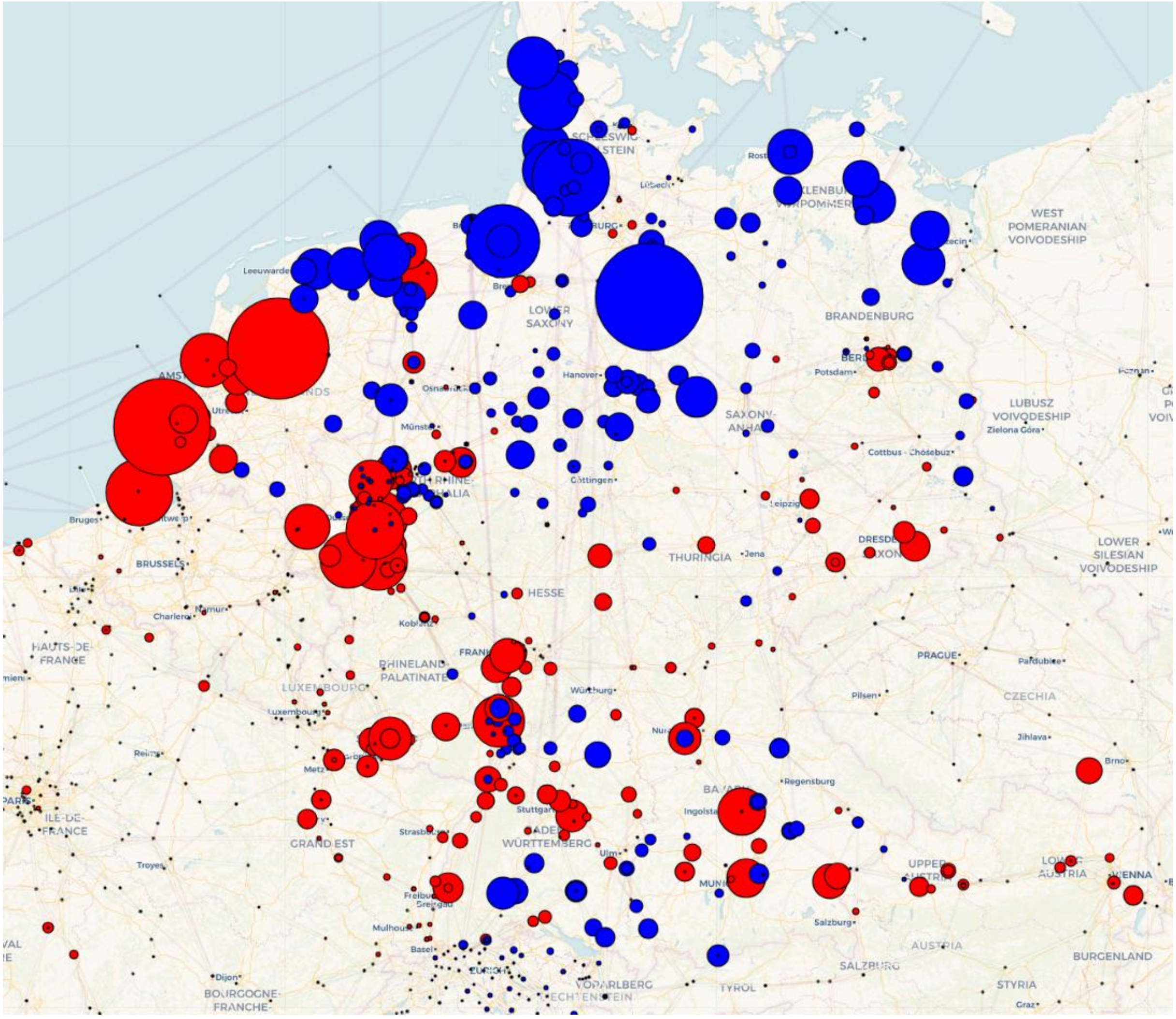

Figure 22: Geographic distribution of redispatch measures in Germany and the Netherlands

Today, redispatch occurs often when wind production, both offshore and onshore, in the Northern part of Germany cannot be transported to the industrial centres in the South. With the heavy buildout of direct current projects (HVDC) in Germany, this issue seems to be less dominant. Down-regulation in Northern parts of Germany is still needed, while up-regulation happens primarily in the

Netherlands. This illustrates a bottleneck in the grid for flow from Northern Germany towards Netherlands and Belgium.

6.2 IMPACT OF HM CASES ON REDISPATCH

The home-market cases impact the system's redispatch in the direction of higher upregulation (Table 6-1 and Figure 23). However, changes in the HM and HM no onshore exemption case are around 0,01%, while the HM no exemption case increases redispatch needs by close to 3%. The higher redispatch needs in the HM no exemption case is a result of the overoptimistic use of the offshore interconnector in the market outcome.

Table 6-1: Redispatch volumes by case (TWh)

	OBZ		HM		HM NoOnshore Ex.		HM No Ex.	
	Up	Down	Up	Down	Up	Down	Up	Down
H2	0.6	-8.8	0.6	-8.8	0.6	-8.8	0.7	-8.8
Batteries	-4.8	4.8	-4.9	4.9	-4.8	4.8	-4.9	4.9
Electrolyser	10.3	-12.5	10.3	-12.6	10.3	-12.6	10.6	-12.8
Nat. Gas	35.3	-1.5	35.3	-1.5	35.3	-1.5	36.2	-1.5
Offshore Wind	0.0	-2.2	0.0	-2.2	0.0	-2.2	0.0	-2.4
Onshore Wind	0.0	-16.7	0.0	-16.7	0.0	-16.7	0.0	-17.3
Solar PV and CSP	0.0	-4.0	0.0	-4.0	0.0	-4.0	0.0	-4.2
Total	**41.4**	**-41.0**	**41.4**	**-41.0**	**41.4**	**-41.0**	**42.6**	**-42.1**

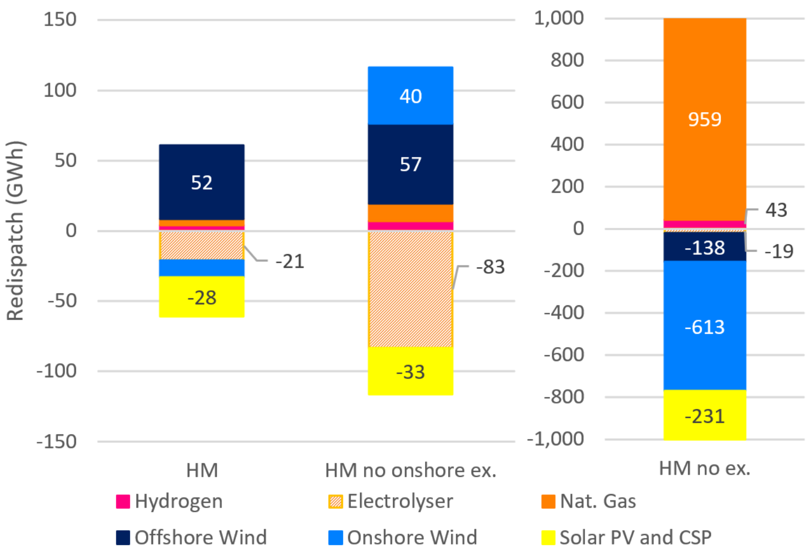

Figure 23: Redispatch in the HM cases relative to OBZ. ***HM no exemption* is displayed at different scale**. Positive values mean that either less renewables were curtailed compared to OBZ, or more (fossil) units were ramped up. Positive values of renewables are therefore favourable, while positive values of fossils imply additional cost.

Renewables

All three HM cases curtail slightly more PV compared to the OBZ alternative. Curtailment of offshore wind is reduced slightly in the first two HM cases, while curtailment of all renewables is increased in the last HM case. Since curtailment of all renewable generation is equally costly in the redispatch optimization (all require additional costly redispatch power, and additionally incur a curtailment penalty for renewables), it seems the optimal nodal redispatch prefers solar curtailment over wind curtailment. The reason for this is presumably routed in the geographic distribution of solar power, meaning that curtailment of solar power is helping the alleviation of grid constraints more than curtailment of wind power. The higher curtailment need in the HM no exemption case is the direct result of too optimistic integration options in the market outcome.

Flexible fossils

All three HM cases show an increase in fossil dispatch compared to OBZ, but the effects of the first two HM cases are low and only increase upregulation needs of gas-based generation by 0.02 %. The HM No exemption case shows the clearest deviation from OBZ, requiring redispatch volumes of an additional TWh to achieve a grid compatible dispatch. The upwards regulation is hereby gas dominated, which increases CO_2-emissions by 0.5 Mton compared to the market outcome.

Electrolysers

Electrolysers contribute to fulfilling redispatch needs with a net increase in consumption by around 2 TWh corresponding to 1.5% of total electricity use for electrolysers in Germany and the Netherlands. Electrolyzer volumes were purposefully not kept at fixed levels, but are price driven and are allowed to deviate from the scheduled market consumption. Differences between OBZ and HM cases are moderate at between 20 and 80 GWh.

6.3 FINAL DISPATCH

Final realised dispatch is constituted of the sum of market and redispatch outcomes. When comparing the final dispatch of the HM cases to the OBZ case, the integration of hub-connected wind is increased, while – depending on the case – integration of other renewables is decreased and generation from thermal gas-based generation is increased (Figure 24). Changes in final dispatch are available on the right hand side of the figure, while market differences are repeated on the left side for comparison.

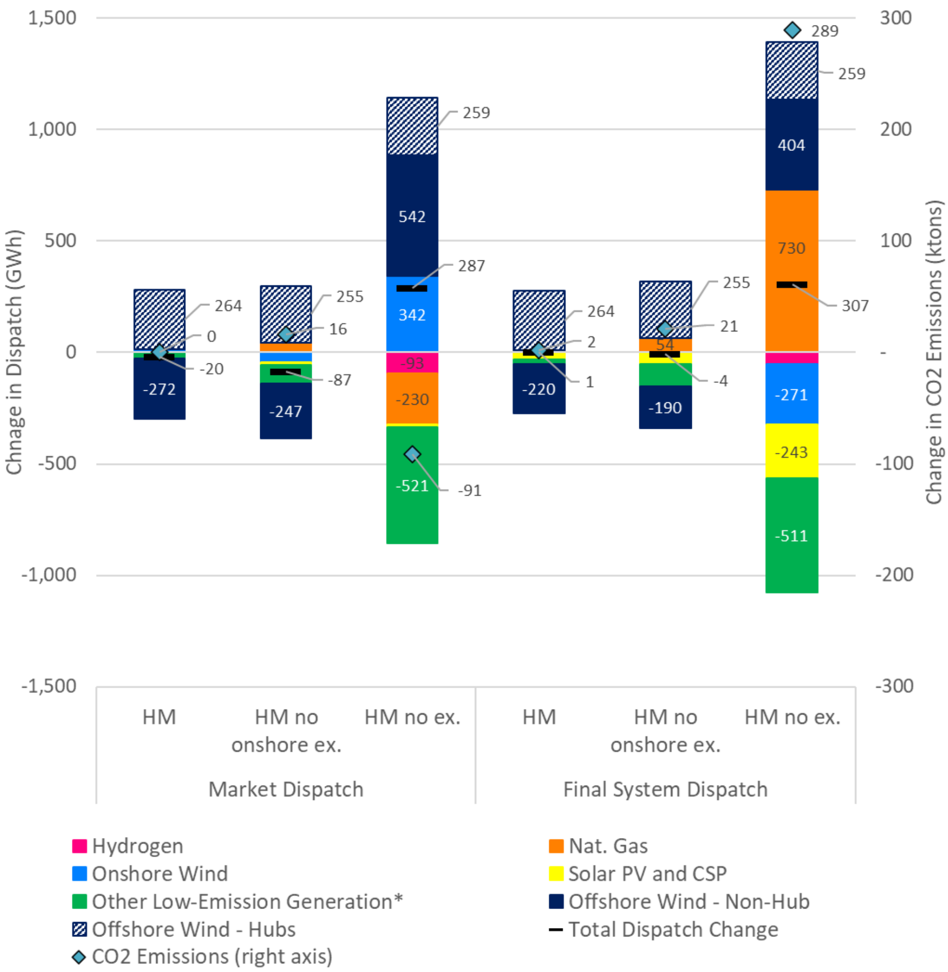

Figure 24: Dispatch changes compared to the OBZ case. Market result on the left, final dispatch (market and redispatch) on the right

It should be noted that the market simulation takes losses into account and thus total generation volumes are not precisely equal in the different cases. Compared to the OBZ case, the main tendencies are:

- Higher dispatch of thermal gas-based generation
- Increased curtailment of solar energy
- Better integration of total offshore wind (note that hub wind energy and non-hub is displayed separately)
- Lower dispatch of baseload thermal power generation (nuclear, biomass) in HM cases, which is not changed by redispatch
- the net impact on integration of renewables remains minor in all cases, rather, other low CO_2 options (biomass, waste, nuclear) are replaced by fossil gas.
- CO_2 emission is increased

Conclusion on Redispatch and Final dispatch results

All HM cases show a less efficient dispatch when accounting for redispatch, illustrated by a higher dispatch of gas-based generation and overall higher CO_2 emission. The underlying reason is that the increased integration of renewable energy from the market results is not feasible in many hours when considering physical grid limits, especially of the offshore interconnector in the case of HM no exemption. Violation of constraints in the onshore grid in the other two HM cases are much less significant and the impact of redispatch is therefore less important.

7 SOCIO ECONOMIC RESULTS

The system cost for supplying the defined demand changes between cases due to the combined market and redispatch effects. The impact of this can be determined on both a system level, as well as for the involved stakeholders.

7.1 COST ELEMENTS

Some cost elements change the fundamental cost of running the system: Differences in fuel use, CO_2-emission cost, variable maintenance cost, redispatch cost. Since the system capacities are kept constant across cases, no changes in CAPEX and fixed O&M are included in the analysis.

Other elements (Electricity sales for producers, electricity cost for consumers and congestion rent) do not change the cost of running the entire system but impact the distribution of cost and income on stakeholders – both between consumers, producers and TSOs as well as between countries and bidding zones. The current chapter summarises the following cost impacts for stakeholders listed in **Table 7-1**.

Table 7-1: Cost elements for stakeholder groups.
The calculation of congestion rent will be further explained in Section 7.2. Impact for producers, consumers and congestions rent are purely based on the market outcome. Redispatch costs are allocated to the TSO, but could impact end consumers through tariffs, and producers could be impacted if cost recovery is not neutral.

Stakeholder costs	Description
Producer surplus	Change in fuel cost, CO2-emission cost, variable maintenance cost and electricity sales
Consumer surplus	Change in cost of electricity
TSO-Redispatch cost	Change in cost for redispatch. Redispatch is assumed to be economically neutral for the producers (actual cost covered by additional income), and the net effect is therefore allocated to the TSOs.
TSO-congestion rent	Changes in congestion income. For the hub structure, the congestion rent shows the total congestion rent related to the flow through the entire hub structure with a simple assumption of a 50/50 split between Germany and the Netherlands, regardless of which part of the hub structure sees a congestion rent (e.g. whether between the two offshore hubs or between a hub and home market)
Total market surplus	Sum of market impacts. Negative value indicates additional cost for market stakeholders
Total system cost	Sum of all costs. Positive value indicates higher cost for running the system.

Socioeconomic cost

The cost summary in this section show total producer surplus, consumer surplus, TSO redispatch cost and congestion rent. The total of all changes reflect the socio-economic cost of the case compared to the reference (OBZ-case). Full cost table with additional elements is shown in Appendix B.

7.2 SYSTEM COST CHANGES

The total cost of the final dispatch **increases in all HM-cases** compared to the OBZ-case with annual additional cost of between 2 and 93 million €, as illustrated by **Table 7-2** to **Table 7-4** below.

The fundamental cost increases are driven by more spending on fuel and CO_2 in the market dispatch and higher redispatch cost (See Appendix A and B for further details).

In the HM-case with full exemptions the higher dispatch of costly thermal generation increases system cost by 2 million € annually. This change in cost is small compared to the redistribution between stakeholders. Total congestion rent falls by 84 million € and producer surplus increases by 84 million €. In other words, revenue moves from the TSO's to electricity producers - mainly Dutch offshore wind at the hub. The main decrease in congestion rent occurs for the Dutch TSO, who receives lower remuneration on flows to neighbouring market zones and through the hubs structure (no flow of offshore wind from the low price hub to the high price onshore bidding zone). Redispatch cost do not increase significantly on a system wide basis, but some redistribution occurs, with higher cost in Germany and lower cost in the Netherlands.

Table 7-2: Socioeconomic comparison of HM relative to OBZ. MEUR/year.

		(Excluding Hubs)			Offshore Hubs		
	All	**Others**	**German BZ**	**Dutch BZ**	**Both Hubs**	**German Hub**	**Dutch Hub**
Producer surplus	84	11	-0	-13	87	-1	88
Consumer surplus	-2	-14	-0	13	-	-	-
TSO-Congestion rent	-84	80	-10	-73	-81	-41	-41
Total market surplus	**-2**	**77**	**-11**	**-74**	**6**	**-42**	**47**
TSO-redispatch cost	0	1	4	-4	-	-	-
Total system benefit	**-2**	**76**	**-15**	**-69**	**6**	**-42**	**43**

Table 7-3: Socioeconomic comparison of HM No Onshore Ex. relative to OBZ. MEUR/year

		(Excluding Hubs)			Offshore Hubs		
	All	**Others**	**German BZ**	**Dutch BZ**	**Both Hubs**	**German Hub**	**Dutch Hub**
Producer surplus	220	44	-38	122	92	-1	94
Consumer surplus	-164	-53	31	-143	-	-	-
TSO-Congestion rent	-66	72	7	-67	-79	-39	-39

Total market surplus	**-10**	**63**	**0**	**-87**	**14**	**-41**	**54**
TSO-redispatch cost	-2	1	-0	-2	-	-	-
Total system benefit	**-9**	**63**	**0**	**-85**	**14**	**-41**	**54**

Table 7-4: Socioeconomic comparison of HM No Ex. relative to OBZ. MEUR/year

	(Excluding Hubs)				**Offshore Hubs**		
	All	**Others**	**German BZ**	**Dutch BZ**	**Both Hubs**	**German Hub**	**Dutch Hub**
Producer surplus	-183	-262	257	-256	79	2	77
Consumer surplus	462	336	-196	322	-	-	-
TSO-Congestion rent	-199	46	-101	-126	-18	-9	-9
Total market surplus	**80**	**120**	**-40**	**-60**	**60**	**-8**	**68**
TSO-redispatch cost	172	7	137	29	-	-	-
Total system benefit	**-93**	**113**	**-177**	**-89**	**60**	**-8**	**-69**

A similar trend as in the HM cases can be seen in the *HM no onshore exemption* case (Table 7-3). Total system cost increase by around 9 million € annually, where revenue is again shifting from congestion rent to producer surplus. Additionally, the more restricted system setup leads an increase in baseload electricity prices by 0,5 €/MWh compared to the OBZ-case, affecting Dutch electricity consumers. Interestingly, total redispatch cost are slightly below the OBZ-case.

The largest change in socioeconomic cost is apparent in the *HM no exemption* case compared to the OBZ case (**Table 7-4**). Offshore wind at the hubs experiences slightly lower increases in electricity sales compared to the other cases, as the added system flexibility lowers baseload prices in the Dutch bidding zone, reducing the advantage of remunerating the offshore wind at Dutch bidding zone prices. Similarly, other Dutch producers face lower income, while German producers benefit from additional export options and the subsequent higher market prices.

Consumers in the two countries face the opposite effect, with lower spendings in the Netherlands and higher spendings in Germany. Total redispatch cost increase by 172 million € compared to the OBZ case, reflecting the higher need for redispatch.

In total, system cost increase by 93 million €, and thus the seemingly cheaper dispatch outcome in the market result is offset by the increased redispatch cost, leading to a less efficient system. When referred to the offshore wind power potential at the hubs, the additional cost corresponds to 5,3 €/MWh, which is a substantial increase of the cost of integrating offshore wind. The total cost increases in the first two HM cases correspond to 0,13 €/MWh and 0,5 €/MWh and thus show a more modest level of increased cost for integrating offshore wind.

7.2.1 CONGESTION RENT

The congestion rent is calculated at the border between two bidding zones in the market simulation. Whenever prices do not converge between the respective bidding zones, a rent is earned for trade volumes times the price difference - it is therefore positive if the power flows from the lower price zone into the higher price zone (intuitive flows) and else negative. The total congestion rent in the modelled system is obtained by summing up all contributions over each border. As the home market cases comprise the hubs as part of the bidding zone, flows between bidding zones refers now only to the hub interconnector and subsequently congestion rent is reduced in volume. Due to general flow changes in the system, not only the borders to the offshore bidding zones, but also other borders are affected.

Within the FBMC framework, non-intuitive flows may occur when welfare is maximized by accepting a negative rent at a particular border while gaining more welfare at other borders. There is therefore a special agreement how to attribute negative congestion rents: it is treated as if a positive congestion rent was earned. The additional claims are compensated by all TSOs earning a positive congestion rent within the hour. This calculation methodology is included when summarizing the market congestions rent. For the hub structure, the congestion rent is calculated based on the flow through the entire hub structure with a simple assumption of a 50/50 split between Germany and the Netherlands, regardless of which part of the hub structure creates the congestion rent (e.g. whether between the two offshore hubs or between a hub and home market). For more details see the appendix.

In total, congestion rents are reduced by between 84 M€ and 199 M€/year (Table 7-5), but the German and Dutch system show changes of up to 245 M€ (Table 7-6). While the level in the first two cases is similar to the increased market revenue for producers at the hubs, the impact in the HM no exemption case is significantly higher. The consumer surplus in this case can therefore be reduced by the negative impact on TSO, ultimately reflected in tariffs.

Table 7-5: Total system congestion rent across cases

OBZ*	20,252
HM	-84
HM No Onshore Ex.	-66
HM No Ex.	-199

*Note: The number for OBZ are the absolute numbers, the rest of the numbers shown are relative to OBZ.

*Note: The numbers under OBZ are the absolute numbers, the rest of the numbers shown in this table are relative to OBZ

Table 7-6: Congestion income for several bidding zones in the OBZ case and differences induced by the HM cases (M€/year)

	OBZ*	HM	HM No Onshore Ex.	HM No Ex.
Germany	3,064	-10	7	-101
German Hub	14	-41	-39	-9
Netherlands	1,049	-73	-67	-126
Dutch Hub	146	-41	-39	-9
Denmark	802	8	9	0
France	2,517	16	18	10
United Kingdom	1,806	17	19	10

7.3 CONCLUSION OF ECONOMIC RESULTS

The economic results for both market and redispatch show that HM cases increase system cost as a result of less efficient dispatch, when some of the grid signals are removed from the market. However, the first two HM cases with full or partial exemption show a cost increase between 2 and 9 M€/year corresponding to 0.13 €/MWh and 0.5 €/MWh of offshore wind at the hubs. Compared to the market value of between 45 and 55 €/MWh, this cost increase is modest at below 1%. However, the HM case without exemption leads to substantial cost increases of 5.3 €/MWh corresponding to up to more than 10% of the market value of offshore wind.

Implications for Policy Makers

From a policy-making perspective, the decision between OBZ and HM cases involves a trade-off between **system efficiency** and **market certainty for offshore wind**. The OBZ case allows the market to allocate flows more freely, leveraging the system-wide optimization potential of FBMC. This case reduces redispatch costs and ensures better utilization of available but scarce transmission capacity. However, it can increase economic uncertainty for offshore wind producers, especially in low-price environments or when grid constraints become binding. In general estimating offshore bidding zone prices in an AHC setup can be argued to be more complicated (and therefore uncertain), than estimating prices in the larger onshore bidding zones. However, the study shows, that with the applied grid assumptions, the impact of the FBMC itself on the values of offshore wind is limited and very similar results would have been obtained if the hub structure would have been modelled with a simple NTC on the interconnector.

The HM case ensures higher market values for offshore wind—especially when the home market is a net importer. However, this comes at the cost of reduced flexibility in grid operations. The pre-reservation of grid capacity for offshore generation limits the market algorithm's ability to find system-optimal solutions, which in turn can increase redispatch needs and lead to suboptimal outcomes for the broader power system.

The different HM sensitivity cases modelled in this study illustrate the importance of how the 70% rule is applied. The **HM no exemption** case allows the market to ignore offshore generation when calculating available transmission capacity, thereby creating a highly flexible dispatch. However, this flexibility comes at the expense of grid realism: **by substantially neglecting physical grid constraints, this case leads to increased redispatch needs and ultimately higher net system costs**, as further elaborated in Chapter 6. While market outcomes may appear efficient, they are not grid-feasible without significant corrective measures in operations. These corrective measures often require the use of gas-based generation in redispatch, not only increasing cost, but also system emissions.

8 ANNEX A – SYSTEM ASSUMPTIONS

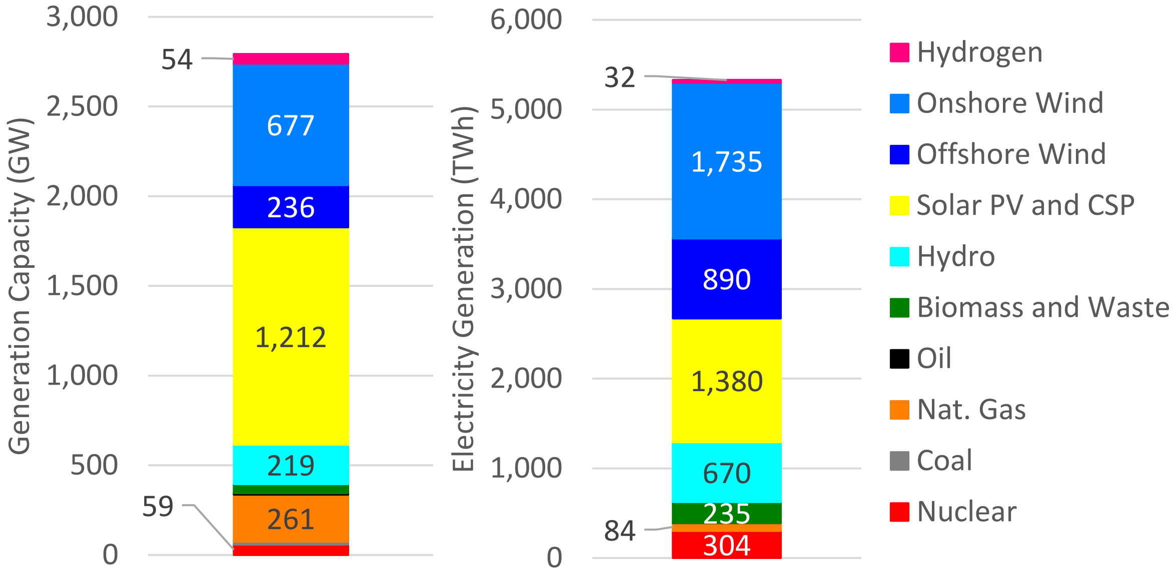

Figure 25: Generation capacity and generation in the modelled system in OBZ.

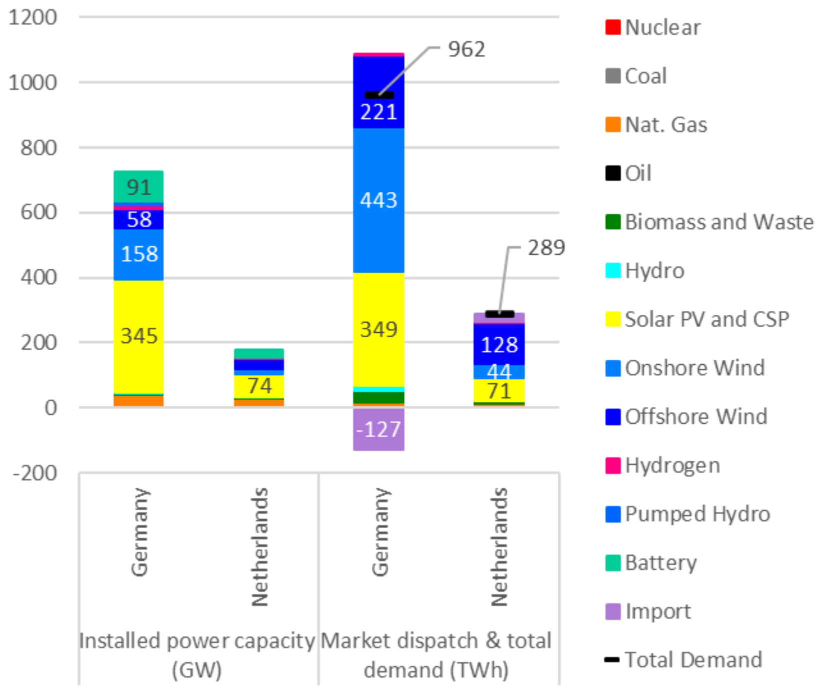

Figure 26: Installed generation capacity, market dispatch and demand in both Germany and the Netherlands

Table 8-1: Assumed full-load hours (FLH) of variable renewable energy (VRE) sources in Germany

	Offshore Wind	Onshore Wind	Solar PV
NEP 2023	3,361	2,308	894
TYNDP 2022	4,504	2,605	866
This Study (before market-based curtailment)	4,387	2,928	1,012
- after market-based curtailment of energy	3,757	2,800	1,012

According to the case definition, the system-wide electrolyser capacity in 2037 amounts to 159 GW_el, resulting in a domestic hydrogen production of 417 TWh_H_2 per year, with an average operational time of approximately 3,800 full-load hours. An additional 243 TWh_H_2 is imported to supply zones with demand exceeding what local electrolysers can produce below the price threshold. Deviations from the hydrogen production levels assumed in the TYNDP are mainly due to differences in price duration curves, influenced, among other factors, by gas prices and cost assumptions.

Higher domestic hydrogen production would require a corresponding increase in thermal power generation. Table 8-2 provides an overview of hydrogen-related results for Germany, the Netherlands, and the overall system under the OBZ case. Germany meets 100% of its hydrogen demand with domestic electrolysers, whereas the Netherlands—due to higher demand and lower installed electrolyser capacity—relies partially on imports. While hydrogen production and imports are outputs of the market model, they are included here to provide system-level context.

Table 8-2: Electrolyser capacity from NEP 2023 and TYNDP 2022 and H2 production from the OBZ case

	Electrolyser Capacity (GW_H_2)	H2 Produced (GWh _H_2)	Electrolyser FLH (h)	H2 Demand (GWh_H_2)	H2 Imported (GWh_H_2)
Germany	18	56,368	3,128	56,368	0
Netherlands	12	45,796	3,942	85,352	39,556
Total System	110	416,683	3,797	659,429	242,746

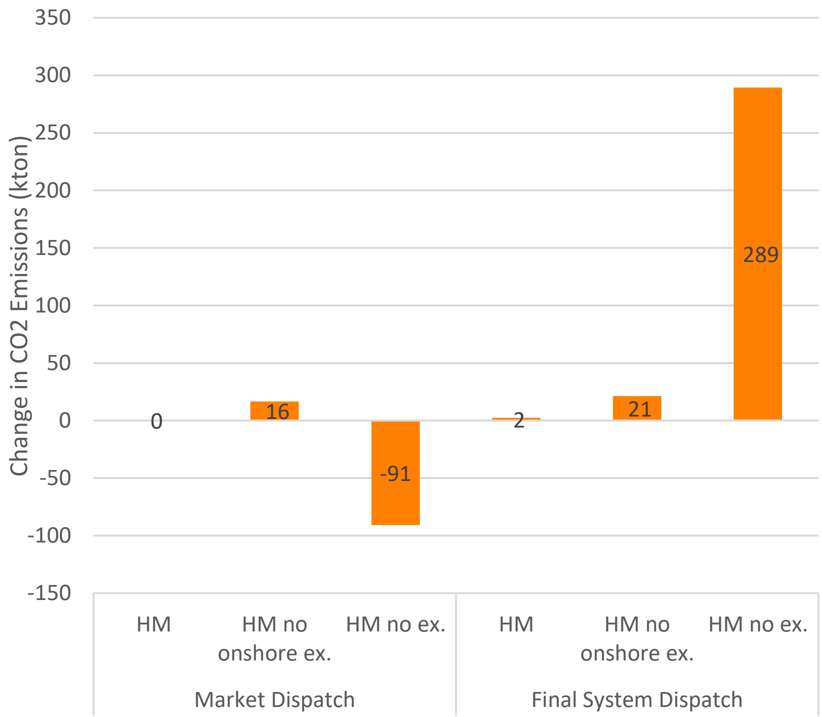

Figure 27: CO_2 emissions in HM model runs relative to OBZ

9 ANNEX B – ECONOMIC RESULTS

9.1 SOCIOECONOMIC COST

Socioeconomic cost

Tables on socio-economic cost show mainly cost elements with two exceptions, which show a revenue: revenue (electricity sales and cross-border congestion rent). What this means is that positive numbers in these tables represent an increasing in cost or a decrease in revenue. Similarly, negative numbers in these tables represent a decrease in costs or an increase in revenue.

Geographical scope

"All" shows the impact for the entire modelled system (not only Netherlands and Germany), and is therefore not the sum of the remaining columns.

Table 9-1: Change in socioeconomic costs in HM relative to OBZ

HM relative to OBZ	M€/Year	(excluding hubs)		(Offshore Hubs)		
	All	German BZ	Dutch BZ	Both Hubs	German Hub	Dutch Hub
Electricity & Heat Producers						
CAPEX generation	-	-	-	-	-	-
O&M	-1	0	-1	1	-1	1
Fuel + CO_2	2	0	-0	-	-	-
Electricity Sales	-85	0	14	-88	1	-89
Subtotal	-84	0	13	-87	1	-88
Consumers						
Electricity cost	5	1	-8	-	-	-
Subtotal	5	1	-8	-	-	-
H_2 producers						
CAPEX	-	-	-	-	-	-
O&M	-0	-0	-0	-	-	-
H_2 Import(+)/Export(-)	1	-	0	-	-	-
Electricity cost	-4	-0	-5	-	-	-
Subtotal	-3	-0	-5	-	-	-
TSOs						
CAPEX transmission	-	-	-	-	-	-
Other transmission	-	-	-	-	-	-
Congestion Rent	84	10	73	81	-25	106
Redispatch Cost	0	4	-4	-		
Subtotal	85	14	68	81	-25	106
Total	2	15	69	-6	-24	19
Market results	2	11	74	-6	-24	19
Market + redispatch	2	15	69	-6	-24	19

(Positive numbers imply an increase in cost or decrease in revenue, negative numbers imply a reduction in cost or increase in revenue)

Table 9-2: Change in socioeconomic costs in HM No Onshore Ex. relative to OBZ

HM No Onshore Ex. relative to OBZ	M€/Year	(excluding hubs)		(Offshore Hubs)		
	All	German BZ	Dutch BZ	Both Hubs	German Hub	Dutch Hub
Electricity & Heat Producers						
CAPEX generation	-	-	-	-	-	-
O&M	-0	-2	0	1	-1	1
Fuel + CO_2	2	-8	8	-	-	-
Electricity Sales	-222	47	-130	-93	2	-95
Subtotal	-220	38	-122	-92	1	-94
Consumers						
Electricity cost	123	-27	101	-	-	-
Subtotal	123	-27	101	-	-	-
H_2 producers						
CAPEX	-	-	-	-	-	-
O&M	-0	0	-0	-	-	-
H_2 Import(+)/Export(-)	9	-	7	-	-	-
Electricity cost	33	-4	35	-	-	-
Subtotal	41	-4	42	-	-	-
TSOs						
CAPEX transmission	-	-	-	-	-	-
Other transmission	-	-	-	-	-	-
Congestion Rent	66	-7	67	79	-26	105
Redispatch Cost	-2	-0	-2	-		
Subtotal	64	-7	64	79	-26	105
Total	9	-0	85	-14	-25	12
Market results	10	-0	87	-14	-25	12
Market + redispatch	9	-0	85	-14	-25	12

(Positive numbers imply an increase in cost or decrease in revenue, negative numbers imply a reduction in cost or increase in revenue)

Table 9-3: Change in socioeconomic costs in HM No Ex. relative to OBZ

HM No Ex. relative to OBZ	M€/Year	(excluding hubs)		(Offshore Hubs)		
	All	German BZ	Dutch BZ	Both Hubs	German Hub	Dutch Hub
Electricity & Heat Producers						
CAPEX generation	-	-	-	-	-	-
O&M	1	3	-0	1	-1	1
Fuel + CO_2	-53	-1	-7	-	-	-
Electricity Sales	235	-259	264	-79	-1	-78
Subtotal	183	-257	256	-79	-2	-77
Consumers						
Electricity cost	-368	168	-215	-	-	-
Subtotal	-368	168	-215	-	-	-
H_2 producers						
CAPEX	-	-	-	-	-	-
O&M	0	-0	0	-	-	-
H_2 Import(+)/Export(-)	-28	-	-18	-	-	-
Electricity cost	-66	29	-88	-	-	-
Subtotal	-94	29	-106	-	-	-
TSOs						
CAPEX transmission	-	-	-	-	-	-
Other transmission	-	-	-	-	-	-
Congestion Rent	199	101	126	18	-57	75
Redispatch Cost	172	137	29	-		
Subtotal	372	238	154	18	-57	75
Total	93	177	89	-60	-58	-2
Market results	-80	40	60	-60	-58	-2
Market + redispatch	93	177	89	-60	-58	-2

(Positive numbers imply an increase in cost or decrease in revenue, negative numbers imply a reduction in cost or increase in revenue)

9.2 CONGESTION RENT

Table 9-4: Congestion rent revenue (m€) in OBZ

AT	751
BE	732
BE_Nautilus	85
BK	825
CH	730
CZ	763
DE	3,071
DK_Bornholm	94
DK_E	126
DK_W	675
Dutch Hub	73
EE	112
ES	933
FI	367
FR	2,518
German Hub	7
IE	256
IT	844
LT	139
LU	43
LV	88
NL	1,121
NL_LionLink	97
NO_M	174
NO_MW	88
NO_N	67
NO_SE	251
NO_SW	375
PL	785
PT	105
SE_M	976
SE_N1	196
SE_N2	619
SE_S	363
UK	1,806

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