An offshore hybrid interconnector in the coupled day-ahead market of Europe – a case study for the Baltic Sea

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Abstract— **Europe's net-zero targets rely on interconnectors to support an integrated electricity market, with high volumes of offshore wind energy. This study evaluates the impact of an additional offshore hybrid interconnector in the Baltic Sea on Europe's day-ahead electricity market. Using the EUPHEMIA algorithm and historical order books (2023–2024), a counterfactual analysis compares two alternative topology setups to a reference case with no such additions. Results demonstrate that a Baltic States-Germany hybrid interconnector would yield greater European welfare benefits than a radial wind farm connection, with significant price effects and commercial flows beyond the hosting countries. The analysis highlights distinct surplus distributions between offshore generators and transmission operators under different setups, emphasizing the complexities of setting up offshore bidding zones. These findings affirm theoretical predictions with real-world data, advocating for sea basin-wide planning and cost-sharing frameworks to address distributional issues and optimize interconnector benefits in Europe's energy transition.**

Index Terms— **offshore wind energy, hybrid interconnectors, offshore grid, day-ahead market coupling, baltic sea**

I. INTRODUCTION

Offshore wind power plays a pivotal role in the European Union's (EU) effort to meet emissions reduction targets due to its higher capacity factors compared to onshore wind [1], its potential to diversify the energy mix [2], and its increasing economic viability [3]. Recent commitments from the EU, Norway, and the UK have raised offshore wind capacity targets to nearly 500 GW by 2050 [4]. To accommodate these quantities of renewable energy, cross-border transmission capacities must be expanded at a higher pace than currently foreseen [5].

In this context, hybrid interconnectors, which support both cross-border electricity trade and renewable energy integration, offer a more integrated approach towards the development of offshore wind than traditional methods. Previous analyzes show how they improve market and grid efficiency while reducing costs and emissions [6–8]. They are gaining attention from academics [9], industry [10], and policymakers [11] especially in the region of Baltic Sea and North Sea. Hybrid interconnectors also facilitate the utilization of offshore wind resources that might otherwise be underdeveloped by leveraging regional imbalances in wind variability [12]. Ultimately, connecting regions with surplus and deficit offshore wind resources enables more efficient energy production, reduces variability in generation, and lowers residual load [13].

For these reasons, an increasing number of long-distance hybrid projects are currently being investigated in Europe [14–16]. They do, however, face challenges related to the setup of offshore bidding zones (OBZ), which influence the economic viability of wind farms and interconnectors [17]. Additionally, the distribution of costs and benefits across connecting market areas, especially between countries, complicates planning [18]. Other challenges include project interdependence [19], system development path dependencies [20], and technology uncertainties [21].

This paper aims to explore the impact of introducing a hybrid interconnector with an offshore wind farm in an OBZ, specifically focusing on power prices, commercial power exchanges, and socio-economic welfare. Unlike existing studies that focus on long-term future projections in the North Sea towards 2030-50 [22–24] or indeed artificial setups [25], this paper examines these effects for the present time (2023-2024) with a focus on the Baltic Sea region. It therefore focusses on a counterfactual analysis to examine key impacts on the power market as if an additional hybrid offshore project were established today.

The contribution of this work is consequently, (1) a back-testing of the day-ahead market clearing with actual historical data as opposed to fundamental modelling, (2) an analysis of price and volume effects, as well as socio-economic welfare, and (3) a focus on the Baltic Sea, an area less studied than the North Sea.

II. METHODOLOGY

For the assessment of the impact of a hybrid interconnector on the electricity market, the European single day-ahead market coupling is studied. It is found that almost 99 % of electricity consumption in Europe is coupled through this market [26]. It operates with zonal pricing, segmenting the internal market into bidding zones. The zonal setup assigns a single market price per bidding zone and market time unit with unrestricted trading within a bidding zone and inter-zone trade being subject to grid capacity limitations [27]. The available grid capacity is calculated within capacity calculation regions, applying either the flow-based capacity calculation method, or the coordinated Net Transfer Capacity approach [28]. The market is being cleared for each time unit by the nominated electricity market operators, that receive calculated grid capacities, aggregate market bids and consolidate these orders [27].

The analysis being presented in this work replicates this procedure by deploying the Simulation Facility. It is a tool being maintained by the nominated electricity market operators and allows market analyzes using historical single day-ahead coupling data and – as done for this study – user-defined inputs [29]. The facility runs EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm), which is used to clear the coupled day-ahead market of Europe [30]. The algorithm facilitates day-ahead market coupling across most European countries, aiming to maximize pan-EU socio-economic welfare by optimizing producer surplus, consumer surplus, and congestion rent while adhering to network constraints. Market participants submit bids to power exchanges, which get aggregated and consolidated into a pan-European order book. The market is then cleared with EUPHEMIA. The algorithm iteratively refines its solution, returning market clearing prices, net positions, accepted volumes, and interconnector flows. The facility runs at hourly resolution, allowing a detailed analysis of the power market.

The setup of the facility supports counterfactual analyses with EUPHEMIA through three types of modifications [29]: (1) network topology changes, including interconnector additions or removals, (2) adjustments to network data, i.e. variations to available interconnector capacities, and (3) market data modifications, involving the introduction of new generators or loads. While some reviewed work exists on the application of the Simulation Facility in general [31], this paper is the first one applying it in a (hybrid) offshore interconnector setup. The necessary modifications to the base network of 2023 and 2024 involving network topology and market data are described in the following section.

III. SCENARIOS AND INPUT DATA

The Baltic Sea is chosen as a case study region for its high offshore wind potential [32] and close vicinity of diverse onshore markets in need of interconnection [33]. The Baltic States (Estonia, Latvia and Lithuania) alone target an offshore wind capacity of 14 GW by 2050 which could reach beyond the electrical demand within these countries [4,34]. In contrast, Germany is expected to be short in offshore wind potentials [35], which underscores the rationale for a long-distance cross-border collaboration in (hybrid) offshore wind development.

Two scenarios are simulated, each with a 2 GW offshore wind farm located in the eastern Baltic Sea, integrated through a new OBZ. Alternative home-market setups, treating the wind farm as an additional generator within Germany's onshore market or the Baltic states, are omitted for simplicity. This aligns with recent Baltic Sea developments, including the planned OBZ for an offshore hub on Bornholm [36]. The OBZ is connected via two different topologies, that are assumed to be HVDC point-to-point connections for their improved efficiency over long distances [37]:

1. Radial: 2 GW wind farm connected to Germany
2. Hybrid: 2 GW wind farm connected to Germany with an additional 0.5 GW leg to the Baltic States

The study perimeter is the entire European single day-ahead market at zonal resolution as illustrated in figure 1. Notice for scenario two that the northern part of the interconnector is split into three equal legs (of 167 GW each) to connect all three countries of the Baltic States equally. This is done for calculation purposes and not to mimic a potential multi-terminal offshore grid. While it theoretically creates more trade opportunities, the simulation shows that internal trade via these legs averaged just 2 MW, which is negligible for this analysis.

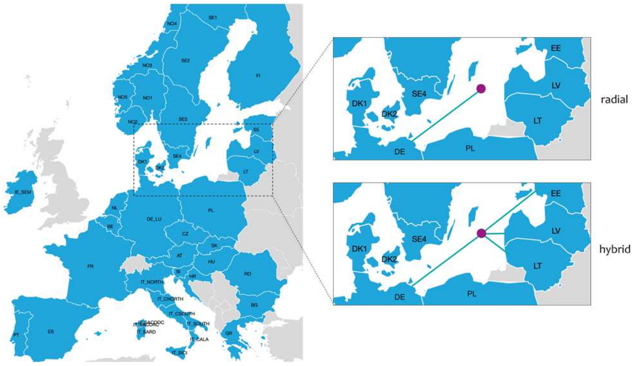

Figure 1: Study perimeter and two simulated scenario topologies

This case study covers the years 2023 and 2024, with results presented as normalized values for one year to level out some non-typical conditions in each year. The weather data for the offshore wind farm is based on the Kriegers Flak region in the southern Baltic Sea and scaled to the required capacity. The wind profile shows typical seasonality, with higher capacity factors in winter and lower in summer, averaging 45 %. The offshore wind farm is the sole generator in the new OBZ, with a fixed bid of 5 €/MWh. It has a 25-year lifespan, scaling investment and operational costs as shown in Table I, based on the Ten-Year Network Development Plan (TYNDP) [38].

Table 1: Costs and parameters for analysis

Financial parameters	
Offshore wind farm	CAPEX: 2,060,000 €/MW OPEX: 65,000 €/MW/a
Transmission system	CAPEX: 1,617 €/MW/km OPEX: 40 €/MW/km/a
WAAC real	5 %
Lifetime	25 years
Distances	
Radial scenario	600 km at 2,000 MW
Hybrid scenario	600 km at 2,000 MW & 100 km at 500 MW

IV. RESULTS

Offshore wind generates effects on the coupled energy system that are visible beyond the market areas to which they are directly connected. This study assesses price effects, commercial power exchanges and socio-economic welfare.

A. *Price effects*

The simulation results in figure 2 show the volume weighted price effects in the day-ahead market with the addition of an offshore wind farm compared to the unchanged historic reference case of 2023 and 2024. Integrating this wind farm reduces prices not just in the hosting market, but also in neighboring regions. In the first scenario, where the 2 GW offshore hub is connected to Germany, prices drop by up to 1.9 €/MWh in Germany, with smaller effects elsewhere. The second scenario, where the Baltic States are connected via a hybrid interconnector, shows slightly smaller price reductions in Germany (up to 1.8 €/MWh), but broader effects across Europe. The Baltic States see the largest price decreases due to the domestic displacement of high-cost thermal generation.

Moreover, the (hybrid) connection of offshore wind to shore can help dampen price variability. Specifically in the case of Germany and the Baltic States price peaks are clipped by up to 20-40 % across both scenarios, while the variance of hourly price fluctuations is reduced by 27 %. This confirms that (hybrid) interconnectors, and the integration of offshore wind enhance security of supply and improve price convergence.

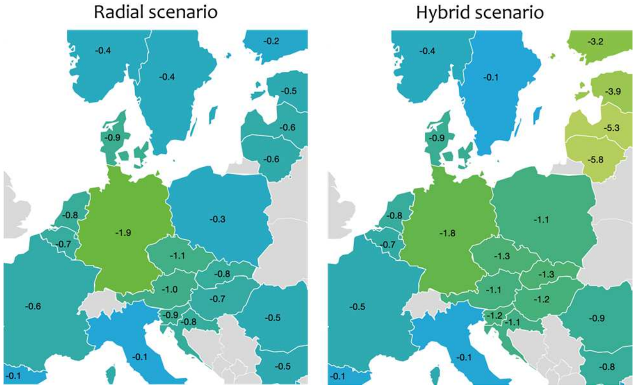

Figure 2: Price effects (volume weighted average) with an additional offshore hub

B. *Commercial exchanges*

The price effects in this simulation result from increased trade volumes and an already well-coupled continental electricity market. Figure 3 shows for the hybrid scenario, how Germany and the Baltic States increase their net exports by 3.84 TWh compared to historical trades, representing 53 % of the total offshore wind supply (7.26 TWh). This highlights how markets not directly connected to hybrid interconnectors are affected by the additional offshore generation elsewhere. This propagation of effects should not be overlooked when discussing cost and benefit sharing across member states for the development of offshore wind, since not only the "hosting" (i.e. directly connected) countries are leveraging the effect of additional green and low marginal cost electricity in the market.

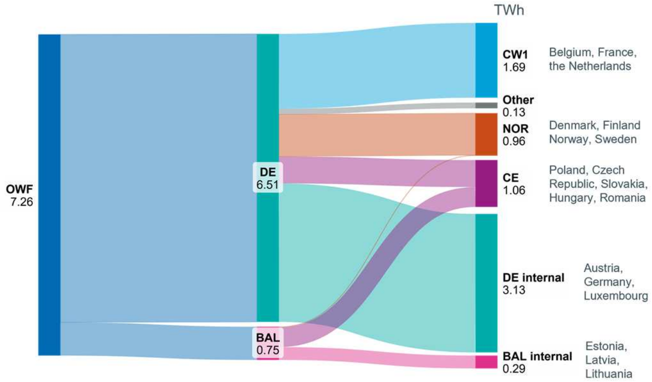

Figure 3: Propagation of electricity injection from the offshore hub into the hosting markets and beyond (grouped into larger regions as per TYNDP)

C. *Utilization rates*

The hybrid interconnector increases the utilization of offshore transmission assets compared to the radial scenario. Figure 4 depicts for the radial setup a utilization in alignment with the wind farm's capacity factor of 45 %. The hybrid scenario exhibits a boost in utilization to 49 % on the southern leg to Germany due to the additional commercial exchange next to the offshore wind integration. The northern leg to the Baltic States operates at a lower capacity (0.5 GW) but shows a similar relative utilization. This is mainly driven by the cross-border flows between Germany and the Baltic States. This observation highlights that hybrid interconnectors may not always function symmetrically, complicating the evaluation of their benefits and cost distribution.

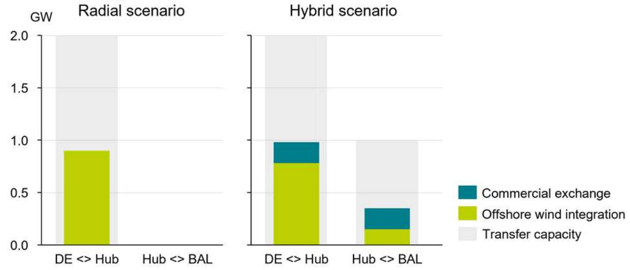

Figure 4: Average utilization of transmission assets

It should be noted that not all similar (hybrid) offshore connections would lead to the same price and cross-border trade effects and utilization patterns. However, the analysis clearly demonstrates that such projects almost certainly affect non-hosting countries, i.e. neighboring market areas around the same sea basin and beyond. This underscores the complexity involved in realizing such transmission systems and sharing out their costs, benefits and risks. The next section deepens this observation by assessing the hypothetical economic case of the assessed topology variants.

D. *Economic Viability*

The price effects and power exchanges suggest benefits beyond the hosting countries. Table 2 confirms this and depicts a positive socio-economic welfare (SEW) effect in both scenarios. The surplus is primarily driven by the 2 GW offshore wind farm as can be seen by the large total SEW in the radial scenario already. The additional interconnection possibility in the hybrid scenario only slightly boosts this surplus due to the optimizer's flexibility in dispatching exchanges.

Table 2: Socio-economic welfare and annualized project costs

SEW in M€ p.a.	**Radial**	**Hybrid**
Producer surplus	-3,600	-5,000
Consumer surplus	9,200	11,900
Congestion rent	11,400	11,500
Total	17,000	18,400
Costs in M€ p.a.		
Offshore wind farm	4,200	4,200
Interconnector	1,800	2,000
Total	6,000	6,200

When comparing the surplus to the annualized project costs, this hypothetical project is economically viable for Europe in both assessed setups, with a slightly better performing hybrid scenario. At the same time, both scenarios show a negative producer surplus, reflecting the displacement of thermal generation by offshore wind in the merit order due to lower sell bids in the order books. Furthermore, a beneficial project from a European perspective does not necessarily provide the same sufficient level of individual benefits for the investing parties. This concerns both (private) developers of the offshore wind farm as well as (merchant or regulated TSO) investments in the transmission infrastructure.

Ultimately, the quantitative findings can only serve as a first indication. Interconnectors being developed in the future will be facing different market and topology conditions both onshore and offshore through increasing levels of renewable generation, other interconnectors and possibly the introduction or change of (offshore) bidding zones. Moreover, the specific cost assumptions are highly uncertain and with new technologies (e.g. floating offshore wind) the effects studied might change. Moreover, the transfer of the results from the Baltic Sea to other Sea Basis should be made with care since cable distances, interconnectivity of markets. onshore energy mixes and wind resources will be different.

Nevertheless, the case study serves as a useful illustration for the underlying distributional effects and key dependencies across the continent and across the value chain (producers, system operators, consumers) associated with the development of offshore wind through hybrid interconnectors. These dependencies concern (1) average price levels, that tend to fall both in onshore markets as well as newly erected OBZ when being connected via hybrid interconnectors [39], (2) unfulfilled sell orders in the OBZ due to a co-optimization of Euphemia with potentially more beneficial cross-border trades between other market areas [40,41], and (3) changes in the market setup during the lifetime of the asset that can deter expected trade opportunities [42].

These dependencies are not unique to hybrid offshore wind connectors but apply to any large energy infrastructure investment with high upfront costs [43]. However, they are heightened in the offshore context due to changing regulatory conditions, which increase project risks and financing costs.

V. CONCLUSION AND OUTLOOK

This study presents an analysis of the European coupled day-ahead market, assessing the impact of a hypothetical offshore hub in the Baltic Sea. Utilizing a counterfactual analysis of historical order books through the Simulation Facility tool, this research offers a unique opportunity to calculate actual market prices and evaluate changes in commercial exchanges and overall socio-economic welfare under two distinct scenarios.

The findings underscore the substantial influence that a single offshore wind farm can exert on electricity markets, whether through a conventional radial connection or a more intricate hybrid configuration. While this impact is beneficial from a European societal perspective—contributing to lower electricity prices and increased system efficiency—it also raises challenges regarding the distribution of costs and benefits across market areas and the broader energy value chain.

The first challenge concerns the potential asymmetry in cost-benefit allocation. As benefits extend beyond the hosting countries and the immediate sea basin, there is a clear need to consider mechanisms for redistributing value from beneficiary markets to hosting regions that a bearing the costs. Addressing this imbalance is crucial to ensuring the economic feasibility of hybrid offshore wind projects. Future research should explore policy frameworks that mitigate these disparities and facilitate equitable investment conditions, thereby enhancing the long-term viability of such projects within an evolving energy landscape.

The second challenge relates to distributional effects along the energy value chain. While the hybrid scenario exhibits superior overall performance compared to the radial configuration, it further suppresses producer surplus – both onshore, by displacing thermal generation bids, and offshore, by structurally lowering prices within the OBZ. This suggests a potential conflict of interest in system development, as the societal benefits of offshore wind deployment must be balanced against the economic viability for individual developers. Further research could provide deeper insights into these trade-offs by exploring additional market topologies for the market integration of offshore wind farms. Additionally, investigating alternative market zone delineations – such as incorporating offshore wind farms into onshore bidding zones – could offer strategies to align market incentives with broader system development goals.

In conclusion, this study demonstrates that hybrid offshore wind projects generate tangible socio-economic benefits not only in long-term future scenarios but also within the present-day electricity market. Accelerating the deployment of such projects will be instrumental in capturing these benefits in due time, fostering Europe to progress with the fulfillment of its offshore wind capacity targets, and advancing its broader climate objectives.

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