Deliverable 3: Analysis for Setting Up an Appropriate Policy Framework for Hybrid Interconnection

Final Report

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Abbreviation	Description
ACER	European Union Agency for the Cooperation of Energy Regulators
BSA	Baltic Sea Area
CBA	Cost Benefit Analysis
CEER	Council of European Energy Regulators
CfD	Contracts for Difference
CI	Congestion income
CRU	Commission for Regulations of Utilities
DA	Day-Ahead
DC	Direct current
DECC	Department of the Environment, Climate and Communications
DG REFORM	Directorate General for Structural Reform
DMAP	Designated Maritime Area Plan
DSO	Distribution Systems Operator
EC	European Commission
EEZ	Exclusive Economic Zone
EU	European Union
FTR	Financial Transmission Rights
GCA	Grid Connection Assessment
HANSAs	Hybrid Network Support Agreements
HM	Home market
KFCGS	Kriegers Flak Combined Grid Solution
MAC	Maritime Area Consent
OBZ	Offshore bidding zone
ORE	Offshore Renewable Energy
OREDP	Offshore Renewable Energy Development Plan
ORESS	Offshore Renewable Energy Support Scheme
OWF	Offshore Wind Farm
PPA	Power Purchase Agreements
RE	Renewable Energy
RESS	Renewable Energy Support Scheme
SEW	Socio-economic welfare
TAG	Transmission Access Guarantee
TYNDP	Ten-Year Network Development Plan

EXECUTIVE SUMMARY

Hybrid interconnections, which are defined in this report as electricity infrastructure that serves the dual purpose of transporting electricity to demand centres and interconnecting adjacent bidding zones, are considered as a first step in the process of establishing an offshore meshed grid. This report identifies the pros & cons of such projects, identifies best practices from selected jurisdictions (UK, Denmark and the Netherlands) and presents several policy recommendations to incentivize hybrid interconnectors in Ireland.

MAIN FINDINGS

Hybrid interconnections can bring about significant benefits to society, but are also characterized by a high level of complexity and costs.

Relative to the traditional radial connection approach of Offshore Renewable Energy (ORE), hybrid projects have the potential to bring about a series of benefits which translate into a more efficient utilization of Offshore Renewable Energy (ORE). The identified **pros** of hybrid interconnection projects are:

- Reduced CAPEX needs for transmission network development from an overall system perspective.
- More efficient infrastructure use. This can be measured in terms of the higher utilisation rates of transmission assets.
- Additional flexibility in power trading among the participating networks, i.e. trade can compensate for the usual fluctuations in RE production.
- Hybrid projects may constitute the starting point for later expansion into a meshed offshore grid. For example, a hybrid project may later evolve into a configuration such as the hubs and spokes design.
- Improved socioeconomic welfare in contrast to counterfactual conventional (radial) reference cases.
- Potential for reduced ORE curtailment, which translates into a more effective utilization of produced renewable energy.
- More efficient dispatchable generation: hybrids with ORE operating in an OBZ reflect the physical conditions in a more accurate manner and thus provide incentives for an efficient dispatch.
- Regulatory compliance: hybrids operating under an OBZ meet the requirements of the 70% rule established in EU regulation.
- Balancing of cross bidding zone electricity price differences.
- Increased security of supply.
- Lower environmental, community and societal impacts.

However, hybrid projects are also characterized by a high degree of complexity and are therefore associated with a series of costs and barriers. The identified **cons** of hybrid projects are:

- The regulatory setup is more complex compared to the establishment of point-to-point interconnectors, as more parties may be involved, and more processes need to be coordinated.
- Higher uncertainty to offshore wind developers in terms of:
    i) revenue risk relative to the Home Market design approach. Under an Offshore Bidding Zone (OBZ) design, the price in that zone will normally be the least of the prices in the two adjacent zones connected to the OBZ. This reduces the revenue for the wind power developer. Revenue may also be affected if the evacuation line is congested.
    ii) the impact from expanding hybrid projects to offshore hubs: the revenue profile of an ORE producer changes when more competitors join.
- Required changes to the regulatory framework and market design configuration: hybrid projects are not compliant with the 70% rule and the absence of priority dispatch under a HM design. This motivates the introduction of OBZs, which requires regulatory changes.

- Cross-border cost and benefit allocation may constitute an issue among the involved stakeholders. Both benefits and costs may accrue asymmetrically to the parties involved requiring negotiation and agreements.
- The timing of investment decisions and capacity deployment is of the essence. Thus, the uncertainty of parallel developments is high.
- Post-Brexit issues:
  - i) The EU legal framework is not valid in the UK.
  - ii) Insufficient clarity with respect to the implementation of the Trade and Cooperation Agreement (TCA) between the EU and UK may prevent an efficient utilization of the infrastructure. This includes but is not limited to the loose market coupling arrangements.

The best practices analysis for hybrid interconnections in the selected jurisdictions (UK, Netherlands and Denmark) reveals substantial differences despite commonalities.

To identify the state of the art in best practices on hybrid interconnection development, the UK, Netherlands and Denmark were chosen as selected jurisdictions. Not only do these three countries have several years of experience in the development of offshore wind and can be thus considered mature markets, but they also have considerable ambitions for the future, including hybrid interconnector development.

Specific information on each country was collected through a review of relevant literature and through interviews conducted with a group of relevant stakeholders (TSOs, NRAs and a commercial ORE developer with operations in the three jurisdictions). A systematic comparison based on the following seven criteria was performed:

- Criterion 1- Offshore and onshore transmission planning framework:
- Criterion 2 - International coordination:
- Criterion 3- Financing of transmission assets:
- Criterion 4- Operation and remuneration:
- Criterion 5 - Government policy towards hybrid projects:
- Criterion 6 – Perception towards EU policy and regulation:
- Criterion 7 - Perceived challenges.

The analysis revealed that although Denmark and the Netherlands share a plan-led approach, there are significant differences between them. For example, regarding anticipatory investments the Netherlands is open for this approach, which facilitates future hybridization of projects. However, Denmark does not consider this possibility. A point of coincidence between Netherlands and Denmark is that ORE development is expected to happen under market terms with minimal or no subsidy.

In sharp contrast to both Netherlands and Denmark, the UK has a developer-led approach in which investors express their interest for developing hybrid projects. In parallel, ORE developments take place with the expectation that there will be voluntary coordination between ORE and interconnector developers. However - in cooperation with government National Grid – Electricity System Operator (NG-ESO) - is currently advancing a Holistic Network Design framework, which entails transitioning from an uncoordinated approach between offshore wind connections and onshore grid reinforcements to a more centralized and strategic approach. This ongoing reform entails transitioning from an uncoordinated approach between offshore wind connections and onshore grid reinforcements to a more centralized and strategic approach.

A point of coincidence among the three jurisdictions is that all are expected to introduce OBZs when hybrid projects become operational. Despite differing degrees of state involvement, jurisdictions coincide in the need to implement a holistic perspective to planning which comprehends the interaction between onshore and offshore energy infrastructure as well as the maritime space. This holistic perspective aims at addressing the inherent complexity of hybrid projects, as well as the variety of goals in a multi-faceted energy transition which involves power-to-x solutions such as the production of green hydrogen. The table below summarizes and compares best practices:

Comparison of best practices

Criterion	*UK*	*Netherlands*	*Denmark*
Planning	**Developer-led model:** developers interact with Ofgem to apply for the establishment of multi-purpose interconnectors (MPIs). Specific projects express interest and initiate a license application which leads to the discussion and approval of a specific regulatory regime.	**Plan-led model:** government publishes and updates the Development Framework for Offshore Wind Energy; TenneT is assigned the role of offshore grid operator. Standardized grid connection approach (2 GW DC platforms for far offshore projects); Anticipatory investments: space is reserved, high voltage facility is hybrid-ready.	**Plan-led model:** parliamentary agreements earmark resources for specific offshore wind projects; Energinet has mandate to build transmission assets. Focus on energy islands, which comprise: i) transmission, ii) generation (possibly storage and demand for PtX), iii) the island itself
Development and ownership of transmission assets	**OFTO model:** developer builds transmission assets and then divests to an offshore transmission operator in competitive process, based on the lowest sum of revenue streams throughout the lifetime of the project.	**TSO model:** TenneT builds and owns transmission assets	**TSO model:** Energinet builds and owns transmission assets
Financing of transmission assets	**Narrow Cap and Floor for the cable and RAB:** partly regulated model, however not the enduring financing model	**Fully regulated:** financed by TenneT, recovered through income cap, supplemented by congestion rents earned.	**Fully regulated:** financed by Energinet, net expenses recovered through income cap. Most of net expenses to be transferred to the offshore wind developer.
Remuneration of generation and hybrid transmission	**Assumption:** future hybrid interconnections will be connected to offshore bidding zones (OBZs)	**Assumption:** future hybrid interconnections will be connected to offshore bidding zones (OBZs)	**Assumption:** hybrid interconnections will be connected to offshore bidding zones (OBZs)

MAIN RECOMMENDATIONS FOR A HYBRID INTERCONNECTOR POLICY FOR IRELAND

Based on the pros and cons analysis and identified best practices, policy recommendations on four main areas (transmission planning, international cooperation, financing of transmission assets and market design) were presented and discussed with relevant Irish stakeholders (industry, state bodies, EirGrid). Recommendations were framed in terms of:

- **Policy instruments:** The tools or control mechanisms used to dictate or substantiate the policy. Some of these instruments already exist in the Irish and EU energy policy framework while some others are recommended implementations.

- **Recommended policy or regulatory option:** The recommended policy/regulatory stance or policy/regulatory approach to implement. It is important to distinguish here between energy policy, which is established by the Irish government, and regulation, which is controlled by the Commission for Regulation of Utilities (CRU). Some of the recommendations may apply to both areas, but this in no way suggests that the due division of responsibilities between policymaking and regulation should be modified.

- **Opted-out policy options:** The policy options that are opted out, which could be implemented as an alternative to the recommended policy option in case the recommended policy is not implemented. This can be understood as a counterfactual to the recommended policy option.

Recommendations on transmission planning

Policy instruments: To address the increasing offshore grid planning requirements, in line with Ireland's ORE ambitions, it is recommended to develop an **offshore transmission strategy**, which includes a **holistic offshore-onshore network design approach**, which is part of Ireland's national grid Development Plans (NDP). The proposed plan should at least:

- Include cost/benefit scenarios and analyses of hybrid interconnection viability, including detailed modelling of the electricity market.
- Enable cooperation with relevant countries (UK + North-Sea and Atlantic Basin countries).
- Complement the Offshore Network Development Plans (ONDPs) prepared in the context of formal cooperation within the EU (ENTSO-E's offshore network development plans).
- Establish the connection approach of planned ORE, including wind farms.
- Determine the required onshore network reinforcements and other onshore interactions resulting from developing the offshore network.
- Present the results of cost-benefit analyses considering a radial/direct connection to shore vs. a hybrid interconnection.

Recommended policy option: To enable the emergence of hybrid interconnections as a preliminary step in the development of an offshore grid, it is recommended that EirGrid develops (possibly standardized) **anticipatory investments** in the radial connection of ORE if the cost/benefit scenarios show evidence that a hybrid project will provide net socio-economic benefits. The main benefit of this approach is to enable a scalable approach rather than investing in bigger and more complex hybrid projects from the outset. According to this model, radially connected ORE can evolve into hybrid projects as investments happen under a smoother trajectory.

Opted-out policy options: The alternative to developing anticipatory investments is to evaluate and develop hybrid interconnections exclusively on a case-by-case and "invest as planned" basis as part of projects that have been originally conceived as hybrid, and to invest as planned without deviating from the initial scope of investment. According to this model, investment is lumpier and more discontinuous.

Summary of recommendations on transmission planning

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Offshore Transmission Strategy, which includes a holistic design approach for onshore and offshore network development. This should include cost/benefit scenarios and analyses of hybrid interconnection viability in cooperation with relevant countries (UK + North-Sea and Atlantic Basin countries) as well as determine the required onshore network reinforcements and other onshore network interactions resulting from developing the offshore network. International ONDP, which is part of the TYNDP prepared by ENTSO-E	Open the possibility to plan and execute **anticipatory investments**, which allow for future "hybridization", if evidence in favour of hybrid interconnections is clear. These investments may be planned and executed in specific areas where potential has been demonstrated.	**Case-by-case planning of investments**: conduct cost-benefit analyses to determine the viability of hybrid interconnections. **Invest as planned:** making investments to the extent necessary and only if there is a guarantee to go ahead with the project.

Recommendations on international cooperation

Policy instruments: Memoranda of Understanding (MoU), more specific agreements such as Letters of Intent (LI) or project-specific agreements such as Hybrid Network Support Agreements (HANSAs) are among the available policy instruments. It must be noted that there does not exist a limited set of instruments to enable cooperation between countries willing to establish mutually beneficial energy infrastructure projects. Instead, these can be bespoke and may depend on the usual practice of a specific jurisdiction.

Recommended policy option: To enable hybrid interconnections, it is recommended that **proactive** cooperation at both the political and technical level priority is prioritized, for example between TSOs. The responsible entity to operationalize this cooperation could be the office of the Minister for the Environment, Climate and Communications of Ireland.

Opted-out policy options: The opted-out policy option is to be **reactive** in the establishment of political and technical cooperation. Rather than choosing and prioritizing countries to establish cooperation, Ireland would wait for other countries or parties (for example, developers) to express interest in the development of hybrid interconnections.

Summary of recommendations on international cooperation

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Memoranda of understanding (MoU), letters of intent (LI), hybrid asset network support agreements (HANSAs)	**Proactively** establish political and technical cooperation between Ireland and relevant countries	Be **reactive** in the establishment of political and technical cooperation between Ireland and interconnected countries

Recommendations on the financing of transmission assets

Policy instruments: There exist three main financing models for transmission infrastructure in Ireland (regulated model, cap and floor and merchant). Given the emerging nature of hybrid interconnections, it is recommended that the three models are considered as point of departure, without committing to one specific financing model for hybrids.

Recommended policy option: it is recommended that although the default model is the fully regulated one, there is openness to the cap and floor model, as this avoids committing to fully underwriting investments on behalf of Irish consumers. One advantage of this model is that it provides a framework that can provide private investors with regulatory certainty which at the same time provides incentives for innovation and efficient operation through the exposure to market-based revenues.

Opted-out policy options: considering only either the fully merchant or fully regulated model.

Summary of policy recommendations on the financing of transmission assets

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Regulated model, partly regulated model (cap and floor), merchant model (compatibility with neighbouring country must be accounted for).	Have openness to the **cap and floor** regime for Ireland's part of a hybrid interconnector project	Consider ***only*** either fully regulated or merchant model depending on the situation

Recommendations on the market design

Policy instruments (for the revision of bidding zone configuration): Articles 32 and 34 of the existing CACM GL Regulation (EU 2015/1222) and article 14(7) of the Electricity Regulation establish procedures to review bidding zones, which means that the process for reviewing bidding zones exists already in EU regulation and is therefore available to Ireland as a Member State. This process can be initiated by a Member State, an NRA, or a TSO. At a national level, the concerned Member State is competent to establish a new OBZ in the territorial waters or the exclusive economic zone. However, if establishing a new OBZ raises concerns and disputes, the process could become slow and bureaucratic.

The review of the bidding zone configuration may interact with Ireland's existing Designated Maritime Area Planning (DMAP) process, which determines the broad area where ORE projects can be developed. An initial, broadly defined area is further refined through a process of public engagement and consultation, expert environmental impact assessments and other expert analysis of the maritime areas, to assess the area's suitability for ORE development (DECC, 2023a).

Policy instruments (for mitigating risks): these may range from forward contracts, financial transmission rights to Power Purchase Agreements (PPAs), Contracts for Differences (CfDs) and the recently debated Transmission Access Guarantee (TAG). The specific choice of instruments depends to a considerable extent on the result of the ongoing EU debate on ORE policy and regulation at the EU level.

Recommended policy option: in line with the recommendation to anticipate investments to enable the gradual emergence of hybrid interconnections which ultimately lead to a meshed offshore grid it is recommended that a proactive plan for the introduction of OBZs is established as follows:

Before 2030 or until Phase 2 is completed:

i) Radial connections can be assumed. In this case, connections to shore are internal transmission lines.

ii) Generation is remunerated according to the HM design.

After 2030 (or the 5 GW target is reached):

When hybrids are part of ORE project solutions:

i) establish OBZ for generation and with one point of the hybrid connected to OBZ, the other point connected to another bidding zone/country.

ii) accompany the introduction of OBZs with appropriate and non-distorting de-risking measures, such as CfDs, PPAs.

Opted-out policy options: the alternative policy option is to proceed with status quo, meaning that all ORE generation is connected to the home market.

Summary of policy recommendations on the market design

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
When relevant proposing a bidding zone review (present EU process considered in CACM regulation should be improved and become more efficient)	**Before 2030:** Radial connections can be assumed (home market zone) **After 2030 (or the 5 GW target is reached):** when hybrids are part of ORE projects: i) establish generation in OBZs	Establish hybrids within home market zones Proceed with status quo (radial connections belong to a home market). Generation is remunerated according to the home market zone.
De-risking instruments for commercial actors (generation)	ii) accompany the introduction of OBZs with appropriate and non-distorting de-risking measures, such as CfDs, PPAs	Being neutral with respect to the risk issues faced by the commercial actor

SUPPLEMENTARY RECOMMENDATIONS ON COST RECOVERY MODELS FOR HYBRID INTERCONNECTIONS IN IRELAND

Following a detailed analysis of specific cost recovery mechanisms for hybrid interconnections in the UK and Denmark – which are among the few countries that have detailed proposals on the matter – three supplementary recommendations were presented. These recommendations must be read in consideration of the overall policy recommendations already outlined.

Recommendation 1: promote ORE development in commercial terms – as much as possible

With the given conditions for offshore wind in Ireland – average wind speeds of approximately 10m/s @100m height and declining offshore wind energy costs – Ireland's ambition to become a net energy exporter is feasible. In addition, it is also in the society's best interest – taxpayers and electricity consumers alike – that ORE development provides tangible gains. It is recommended therefore that ORE development happens, to the largest possible extent, on commercial terms. That is to say: there should be a clear policy objective to reduce subsidies and increase the efficiency of the sector in the medium term (10 years).

Recommendation 1A: revise the auction design for the fortchoming phases in the transition to the Plan-led regime and aim at increasing efficiency

One desirable property of well-designed auctions is their ability to deliver efficient outcomes. In the context of offshore wind auctions, this means that producers with the lowest cost obtain the right to produce and obtain state aid. Taking into consideration the declining trend in state aid granted to offshore wind producers in Europe, Ireland's Phase 1 auction results (86,05 EUR/MWh) have the potential to become significantly lower in the coming phases of the transition the plan led regime.

It is recommended that an ex-post analysis of Phase 1 auction results supports the identification of factors that played a role in the participants' bidding behaviour. More importantly, the understanding of these factors should support re-designing the auction mechanism and re-considering policy decisions to induce efficiency in the forthcoming phases. Although it is outside the scope of the present report, it is possible to hypothesize that a combination of risk considerations and supply chain constraints could have influenced the result of the Phase 1 auction.

Recommendation 1B: make state revenue maximization and non-financial considerations an important element of the ORE policy

Another possible objective of practical auction design is revenue maximization - when an auctioneer sells goods or services, the aim is to collect the maximum possible revenue. Ireland, as owner of vast maritime resources (Irish landmass only makes up 10% of Ireland's territory) has both the right and the duty to maximize the societal benefit on behalf of Irish citizens. One possible way of achieving this is through a concession-based mechanism in which the state grants ORE developers the right to use the seabed throughout the lifetime of an ORE generation project, based on revenue maximizing auctions.

Furthermore, non-financial considerations can also be incorporated to the ORE policy, including auction mechanisms. In ORE policy development, there exist a series of non-financial aspects which, by their nature, cannot be measured by a price or a financial bid. For example, the impact of ORE development on the environment and communities, as well as the decommissioning approach of ORE generation facilities are all relevant aspects that a holistic ORE policy development may value and incorporate.

It is recommended that revenue maximization and non-financial considerations are incorporated into Irish ORE policy.

Recommendation 2: be open to the cap and floor regime for Ireland's part of a hybrid interconnector project

One of the main recommendations of this report is to have openness to the cap and floor regime, as this approach can provide certainty and positive incentives for the efficient operation of an interconnector. However, the detailed analysis on proposed cost recovery mechanisms in the UK and Denmark allow adding *regime compatibility* as one additional argument for this approach.

Based on Ireland's Policy Statement on Electricity Interconnection (July 2023) there is a commitment to develop an interconnector with the GB market beyond 2030, which will be potentially hybrid. Taking this into consideration, openness to the Cap and Floor regime by Ireland – which will presumably be the enduring regime for the development of OHAs in the GB market – would greatly facilitate aligning incentives and reaching a common understanding in relation to the revenue and cost sharing agreements.

Recommendation 2A: assess existing tariff frameworks to advance ORE development and develop initiatives that support Ireland's energy transition.

One central element for the transition to the plan led regime and the emergence of hybrid interconnection projects is network usage. The availability of network capacity, as an inherently scarce resource, conditions location decisions, as the Phase Two policy statement (March 2023) revealed: ORE Designated Areas would be geographically aligned with available onshore grid capacity.

The underlying analysis for this report indicates that EirGrid's existing tariff framework lives up to international best practices, as it already sends locational and time-varying price signals to network users. However, it is recommended to assess this framework in an ongoing basis and to develop initiatives that support Ireland's energy transition. In particular, it is recommended to: i) assess if existing tariffs incentivize efficient network usage, ii) develop a dedicated tariff framework for ORE development which aligns with the chosen cost recovery mechanism for hybrid projects and the overall offshore grid, and iii) to develop incentives to optimally integrate Power-to-X solutions into the Irish grid.

Recommendation* 3: *adopt a decision on the introduction of OBZs as part of the transition to the plan-led regime

It was previously argued that to allow for a gradual emergence of hybrid interconnections, a proactive decision on the introduction of OBZs should be adopted. It was also mentioned that the review of the bidding zone configuration may interact with Ireland's existing Designated Maritime Area Planning (DMAP) process, which determines the broad area where ORE projects can be developed.

The review on specific cost recovery models proposed in Denmark and the UK (section 3.3) has reinforced this recommendation. The main lesson obtained is that the cost recovery mechanism for hybrid interconnectors is understood as a joint package of decisions, in which the transmission asset's revenue and cost framework is designed in parallel to the market design environment. Both decisions are taken simultaneously.

Recommendation 3A: establish a possible pathway for sequential build-up, which opens up to "hybridization" and re-negotiation of the regulatory framework with ORE generators

It has been recognized that hybrid projects can be complex due to the technical requirements and the need to establish political, technical, and regulatory cooperation between different institutions across jurisdictions.

To account for the possibility of hybridization in Ireland, it has been recommended that Ireland adopts a policy commitment to connect all ORE generators radially under a HM solution before 2030 (or the 5 GW target is reached) and to announce the establishment of an OBZ afterwards to facilitate hybridization. It was also recommended to identify a suitable de-risking measure to allow ORE developers hedge the increased volume and price risk present due to the establishment of OBZs.

In addition, it is recommended to initiate a dialogue with industry stakeholders to understand the conditions that would have to be met for a possible change in the market design and to consider the establishment of a compensation for a possible change in regulatory setup. Such compensation mechanism would be an addition relative to the suitable de-risking measure.

RECOMMENDATIONS FOR FURTHER WORK

As with any comprehensive piece of work, there remain questions that cannot be answered in full detail. In what follows, a few recommendations for further work are presented:

1. Regarding energy modelling to substantiate offshore transmission planning and to support bilateral talks with potential partner countries:

   - **Developing a model of Ireland's electricity system in an EU context:** one fundamental first step to illustrate the socio-economic benefits of interconnectors in general and hybrid projects in particular is developing a model of Ireland's electricity system, which includes interconnections with relevant countries, such as Great Britain, Belgium, Netherlands, and other surrounding countries in Western Europe. Such model will provide relevant Irish stakeholders (DECC, EirGrid, CRU) with a tool to build relevant evidence base to substantiate decisions.
   - **Defining a baseline scenario and several counterfactuals with pre-defined time horizons to conduct specific modelling exercises that allow quantification of net socio-economic benefits and distributional impacts:** defining a baseline scenario entails defining future generation, demand, and interconnector build-up for the whole modelled area in pre-defined time horizons. For instance, as part of the reference case, interconnectors may be modelled in parallel to radially connected generation which will support the quantification of socio-economic benefits as well as the distributional implications (producer surplus, consumer surplus, congestion rents). Several counterfactual configurations could include:
     - Hybrid projects operating in home markets and hybrid projects operating in offshore bidding zones.
     - Sequential build-up of generation sites and development of Power-to-X configurations, including electrolysis located onshore and offshore as well as other developments such as the activation of demand from data generation centres and the re-purposing of the natural gas infrastructure.

   The idea behind this recommendation for further work is to create a solid energy system modelling base for Ireland, and to conduct detailed analyses such as the ones reviewed in section 1.2 of the present report. These analyses should build up on Ireland's existing ambitions, outlined in its Climate Action Plan, the Hydrogen Strategy as well as the Industrial Strategy for Offshore Wind.

2. Regarding the regulatory framework and the cost recovery mechanism:

   - **Conducting analyses to determine distributional impacts of different cost recovery mechanisms for the offshore electricity grid.** One implication of Ireland's transition to the plan-led regime is the substantial buildout of the offshore electricity grid, leading to a considerable growth in its regulated asset base (estimated in the order of 5 billion EUR) by 2030. An enduring cost recovery mechanism for its new role as asset owner of the offshore electricity grid will be required and with it a tariff framework for ORE development may be necessary (see Recommendation 2A). Considering these developments, it is recommended to investigate the interplay between financial aspects of the offshore grid buildout and energy systems modelling. Specifically, the study would investigate different cost recovery mechanisms under different assumptions on equity and borrowing costs in the framework of energy systems modelling. In this way, the impact of electricity prices, tariff modelling and financial assumptions could be jointly assessed.

3. Regarding the institutional and organizational arrangements to facilitate the transition to a plan-led regime and the emergence of hybrid projects:

- **Conducting analyses of institutional and organizational frameworks:** as has been noted earlier in this report, the transition to a plan-led regime as well as the planning of hybrid projects can be complex. This will require a considerable effort to streamline processes and to facilitate the interaction of the different entities involved, possibly requiring a re-organization and re-evaluation of roles within Ireland's institutional framework. A detailed analysis of the technical competences and the checks and balances between involved institutions may be necessary.

INTRODUCTION

This report concludes and summarizes the findings and recommendations of *Deliverable 3: Analysis for Setting Up an Appropriate Policy Framework for Hybrid Interconnection*, which is part of a European Funded project that seeks to inform and underpin the move to a plan led regime for Offshore Renewable Energy in Ireland.

The analysis has revolved around the question of *what policy and regulatory framework should Ireland adopt to incentivize hybrid interconnection projects*. The question is relevant as Ireland is in the process of transitioning away from a developer-led model for ORE development into a state-led approach. The gradual transition to the new regime, which has been divided into three phases, aims at facilitating the country's ambition to deploy 5 GW offshore wind capacity by 2030 with a further 2GW to be developed for non-grid use including the production of green hydrogen. ORE development is part of Ireland's effort to reduce its emissions by 75% by 2030 and to achieve up to 80% of renewable electricity by 2030.

More generally, Ireland aims at transforming its economy and to decouple economic growth from carbon emissions. To this end it has outlined a National Offshore Wind Industrial Strategy to establish and develop a strong supply chain which facilitates job creation and supports the country's ambition to become a net energy exporter.

In this context, the development of interconnectors will support the achievement of these goals but will also help integrating Ireland with the EU internal market for electricity as well as enhancing integration with its closest neighbour, the UK. To date, Ireland has interconnection capacity of 500 MW. According to Ireland's policy statement on Electricity Interconnection (July 2023), this is expected to increase to up to 1700 MW by 2026 and to more than 5000 MW by 2033 if the full potential capacity materializes.

Hybrid interconnectors are expected to contribute to this increased transmission capacity and to support overall ORE development, as Ireland has committed to exploring the feasibility of hybrid projects and the possibility of progressing to execution if Ireland's proposed offshore grid planning framework provides supporting evidence that these will bring about net socio-economic benefits.

Confirmed by a review of energy systems modelling evidence, one of the key findings of the present report is that hybrid projects have the potential to bring about major societal benefits in terms of increased trading opportunities and strengthened security of supply. Relative to the more traditional radial connections of offshore renewable energy (ORE), hybrid projects can increase efficiency and significantly reduce environmental and community impact.

However, evidence gathered through stakeholder interviews and a review of the relevant literature on the matter have also confirmed that hybrid interconnector development is a complex process which requires significant cross-border cooperation as well as a solid coordination between the onshore and the offshore energy infrastructure and attention to its interaction with the maritime space. To address this complexity, the researched jurisdictions coincide in the need to implement a holistic perspective to planning. While technical solutions, financing and market frameworks differ, they have all deployed institutional frameworks to address complexity.

Structure of the report

The report is structured into three main chapters, which reflect the methodological approach and sequence pursued in the project.

Chapter 1 analyses pros & cons and identifies best hybrid interconnection practices in selected jurisdictions, namely the UK, Denmark, and Netherlands. Starting with an analysis of the European and Irish context, the chapter identifies the main regulatory principles that are at stake in the development of ORE. The chapter reviews a wide variety of energy system modelling studies, which highlight – under different scenario configurations and for different jurisdictions – the net socio-economic benefits of establishing hybrid interconnectors.

Based on stakeholder interviews and a review of the relevant literature, the chapter then summarizes the best practices identified in each jurisdiction. To this end, six different criteria (offshore and onshore transmission planning framework, international coordination, financing of transmission assets, operation and remuneration, government policy towards hybrid projects, perception towards EU policy and regulation and perceived challenges) were used to produce country profiles which are then compared and analysed.

Based on an expert understanding of best practices and pros & cons, **Chapter 2** begins by presenting a series of working hypotheses that would inform the design of policy recommendations. These were then summarized into a policy options paper which formed the basis for discussion with relevant Irish stakeholders. The Irish TSO EirGrid, Ireland's National Regulatory (NRA) CRU, industry representatives and representatives from a variety of state bodies were engaged to provide input to the recommendations presented.

A series of multilateral meetings and two thematic workshops – one on overall policy options and another one on cost recovery models – gave stakeholders the opportunity to contribute with their viewpoints.

Figure 1: Process underlying the recommendations.

The policy recommendations, which are discussed in depth in section 2.5, revolve around four main themes:

- Transmission planning
- International cooperation
- Financing of transmission assets
- Market design

Once the main recommendations were established, **Chapter 3** analysed existing detailed proposals on cost recovery mechanisms currently under consideration in the UK and Denmark. Although such proposals are not final, they reflect realistic and detailed policy and regulatory considerations on the matter, as well as alternatives which could inform Ireland's own design of a cost recovery model. Before presenting three supplementary recommendations for the design of Ireland's cost recovery model, two specific topics were discussed in the chapter. First, regime compatibility or how can transmission asset developers jointly develop hybrid interconnector projects despite being governed by different regulatory regimes. Second, de-risking measures that could be applied in Ireland to mitigate the increased risk perceived by ORE producers operating in an offshore bidding zone, relative to the operation in a home market.

1. ANALYZING PROS & CONS AND BEST HYBRID INTERCONNECTION PRACTICES

1.1 European context

1.1.1 What is the existing regulatory framework for offshore renewable energy (ORE) and hybrid projects?

The market design and regulatory framework of the European Union (EU) internal market for electricity, which has evolved over decades, operates under a series of principles that are not technology specific. Relevant for ORE is the fact that since the introduction of the EU Clean Energy Package (2019), all renewable energy (RE) generators are exposed to the same market conditions as all other market participants.[1] In this respect, two key regulatory principles are:[2]

- **Full balance responsibility:** ORE producers shall be financially responsible for the imbalances they cause in the system
- **Absence of priority dispatch:** ORE producers do not have priority dispatch, which means that Transmission System Operators (TSOs) shall not alter the order of economic bids to favour RE over other producers

With regards to the transmission infrastructure, hybrid projects – unlike standard radial connections – serve the dual purpose of transporting electricity to demand centres and interconnecting adjacent bidding zones[3]. The existing EU regulatory framework does not either have a separate set of rules for hybrid interconnectors and are bound by the same principles as their point-to-point counterparts, notably:

- **The 70% rule** which states that at least 70% of cross-zonal capacity on an interconnector must be assigned for trade in the day-ahead and intra-day timeframes.[4]

Another long-standing regulatory principle is **unbundling**, which states that energy generation should be separated from the operation of transmission networks. In the context of hybrid projects, this means that ORE generation assets and transmission infrastructure must not be part of the same company, which amounts to ownership unbundling. However, this does not prevent ORE generators from building its own connection to shore and then divesting it to a third party, which would then operate the asset, as is the case of the Offshore Transmission System Operator (OFTO) model that exists in the UK.

Regarding transmission infrastructure investments (including hybrid interconnectors), TSOs are responsible for making investment decisions that live up to the ten-year network development plans that these submit to National Regulatory Authorities (NRAs). These plans indicate the required transmission expansion and upgrades for the next ten years, as well as the investments to be executed in the next three years, including a time frame for all investment projects. The responsibility for executing investments is also the TSOs' responsibility which

[1] Except for small-scale renewable producers (less than 400 kW) and demonstration projects with innovative technologies. See Regulation (EU) 2019/943 on the internal market for electricity (European Commission, 2019).

[2] Article 5 (Full balance responsibility) and Article 12 (Dispatching of generation and demand response) in the Regulation (EU) 2019/943 on the internal market for electricity (European Commission, 2019).

[3] This paraphrases the European Commission's , see the "EU Strategy to harness the potential of offshore renewable energy for a climate neutral future" (European Commission, 2020).

[4] The 70% rule is stated in Article 16(8) of the Regulation (EU) 2019/943 on the internal market for electricity (European Commission, 2019).

obtain approval from regulatory and oversight authorities. The **main cost recovery mechanism** for these investments is through a combination of tariffs charged on network users and the collection of congestion rent.

1.1.2 Kriegers Flak derogation and the need for regulatory adjustments for hybrids

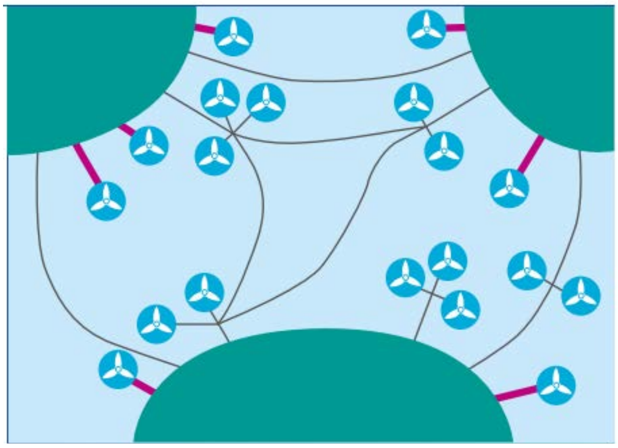
Although the existing EU market design and regulatory framework is broad enough to enable ORE and hybrid projects, the development and operationalization of the Kriegers Flak Combined Grid Solution (KFCGS) made it evident that adjustments to the regulatory framework would be required if hybrid projects were to live up to some of the main EU regulatory principles governing ORE.

The KFCGS, which is the only operational hybrid interconnector in the world, obtained in 2020 a 10-year derogation from the EU Commission from complying with the 70% rule. The derogation, which can be prolonged up to 25 years, states that the remaining transmission capacity after deduction of the wind feed-in forecast of the offshore wind farms (OWFs) is to be made available to the market. This entails giving a *de facto* priority dispatch to ORE generators.

To illustrate the issue with clarity, consider the three following setups for ORE generation:

- **Radial connection in a Home Market (HM):** Under a conventional radial interconnection of ORE (see Figure *2*), connection to shore is an internal line in an onshore bidding zone - the Home Market (HM) - and obtains the HM price. This is the way in which all existing ORE is connected today.

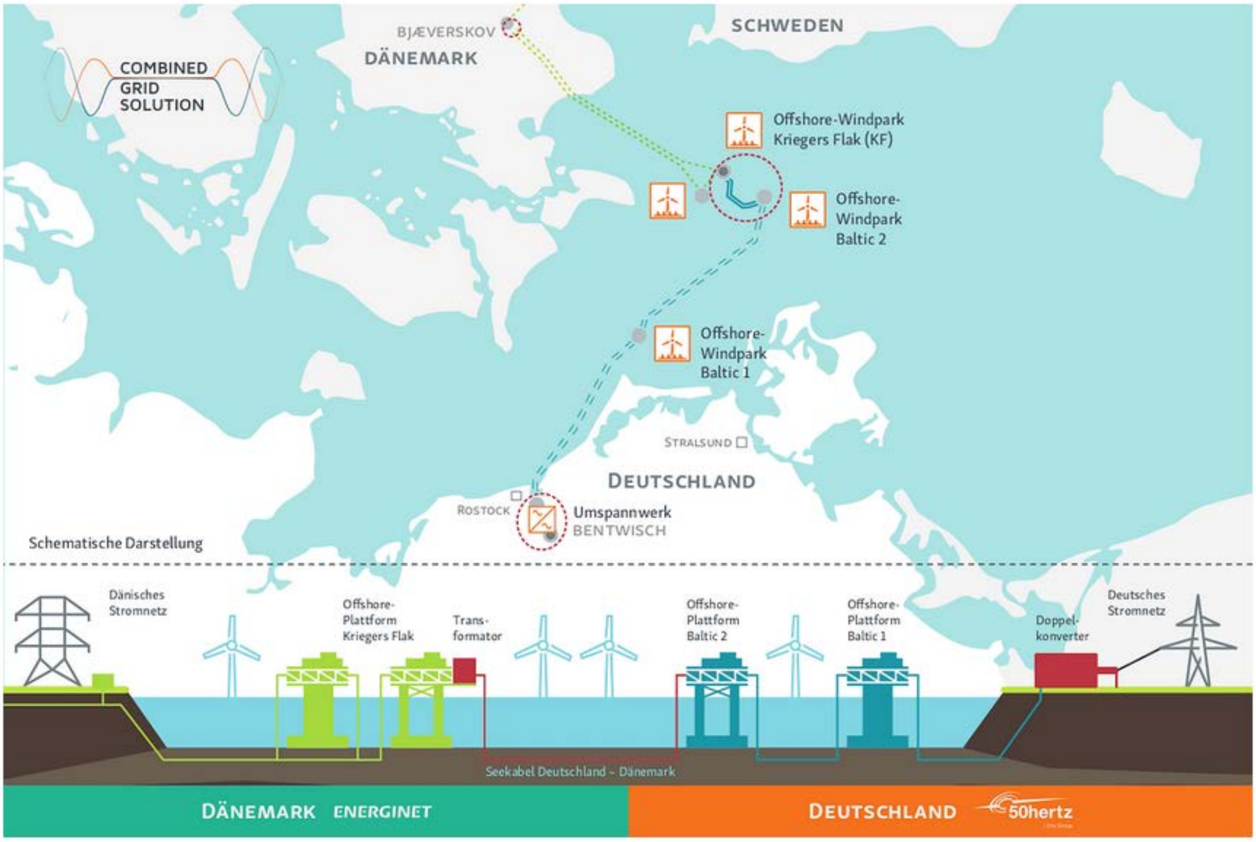
Figure 2: Radial connection of a wind farm



Source: ENTSO-E (2020)

- **Hybrid interconnection in a HM:** If there is a hybrid interconnection under the HM design the line serves the dual purpose of an evacuation line and an interconnector. In this case too, ORE producers obtain the HM price in their corresponding zones. In Figure 2 (which is a real-life example of this situation) German windfarms obtain the German price and Danish windfarms obtain the East Denmark price (DK2). The cable connecting the farms is a hybrid interconnector.

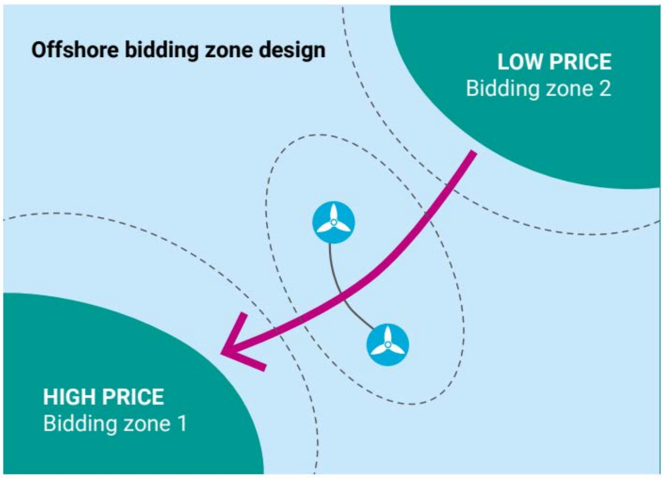
Figure 3: Schematic representation of the Kriegers Flak Combined Grid Solution



Source: 50hertz (2020)

- **Hybrid interconnection in an Offshore Bidding Zone (OBZ):** If there is a hybrid interconnector under an OBZ, the ORE generator obtains the OBZ price (see Figure 4 and assume that the line in fucsia is a hybrid interconnector). In this case, it will be prices which determine the flow and thus the optimal utilization of the hybrid interconnector, either as a cross-border interconnector between the low price zone and the high price zone (see Figure 4) or as an evacuation line for the ORE produced at the OBZ.

Figure 4: A hypothetical offshore bidding zone (OBZ).



Source: ENTSO-E (2020)

The table below (Table 1) compares the three possible arrangements for ORE, with and without hybrid interconnections and discusses its compliance with the absence of priority dispatch and the 70% rule:

Table 1: Comparison of ORE arrangements

Principle	Radial connection under a Home Market (HM) degisn	Hybrid interconnection under the HM design (Kriegers Flak derogation)	Hybrid interconnection under the OBZ design
Cross-border trade (70% rule; art. 16(8) in 2019/943). Minimum cross-border capacity given to the day-ahead market timeframe.	If the bidding zone to which the ORE generator is connected to another bidding zone, this interconnection needs to comply with the 70% rule. However, the flow on the ORE connection to shore is an internal line and is not bound by this rule.	Partly compliant, as it is the remaining capacity after all wind is evacuated to shore, which is considered as part of the 70% calculation.	Hybrid project complies with the 70% rule as all flows are cross-border in an OBZ setting.
Absence of priority dispatch (art. 12 in Regulation 2019/943): TSOs shall not prioritize renewables above other technologies when dispatching.	Complies with the principle, ORE producer is connected to shore (the HM) via an internal line.	Not compliant, as ORE has priority on the use of the cable relative to other producers. All ORE generation must be evacuated first.	Compliant, as ORE competes with all other producers for the use of the cable. Price at the OBZ (which will usually be equal to the uncongested side of the cable) dictates the flow.

Source: Author's interpretation of EU regulatory framework

Under the second configuration (hybrid interconnector under a HM), the issue arises when the connection to shore becomes congested, as the line cannot simultaneously provide 70% of interconnection and send all produced wind to shore, which is a flow on an internal line. TSOs are then faced with two choices:

i) offering 70% interconnector capacity and if congestion occurs, then curtail wind output, or

ii) not complying with the 70% rule and only offering the remaining capacity after all wind is evacuated, which violates the absence of priority dispatch principle, which is what the Kriegers Flak derogation entails

Price formation in an OBZ

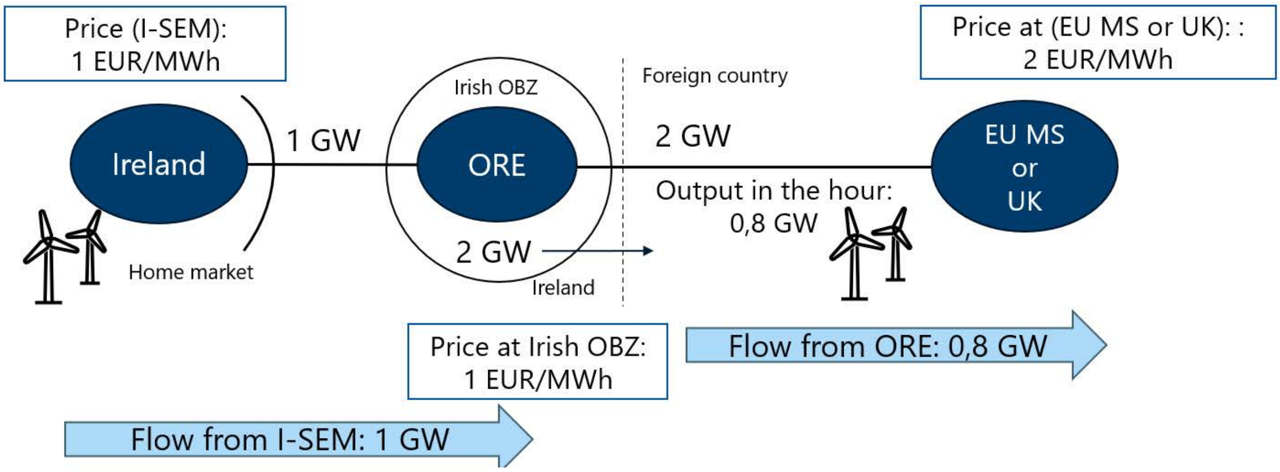
ORE stakeholders in the EU (such as ENTSO-E, EU Commission, ORE generators, ACER and CEER) coincide that the establishment of OBZs can secure the efficient utilization of hybrid infrastructure and reduce the need for TSO intervention through measures of countertrade and redispatch.

By "efficient" it is meant that price formation will determine the optimal flow of ORE generation to the geographical areas where it is needed most while ensuring the optimal usage of the hybrid interconnector, either as an evacuation line or as an interconnector. To see this, consider the following examples of price formation in an OBZ:

Example 1: ORE generation below full capacity at an OBZ

In a first example, ORE generation (2 GW capacity) is located in an OBZ but output in the given hour is 0,8 GW. As the price at the I-SEM coincides with the OBZ, there will be a flow of 0,8 GW from the OBZ to the high price zone and the producer earns. In addition, onshore producers at I-SEM will be able to export 1 GW and total flow will be 1,8 GW, leaving unused capacity of 0,2 GW on the interconnector between the OBZ and the neighbouring country.

Figure 5: Example 1 - ORE generation below full capacity at an OBZ.

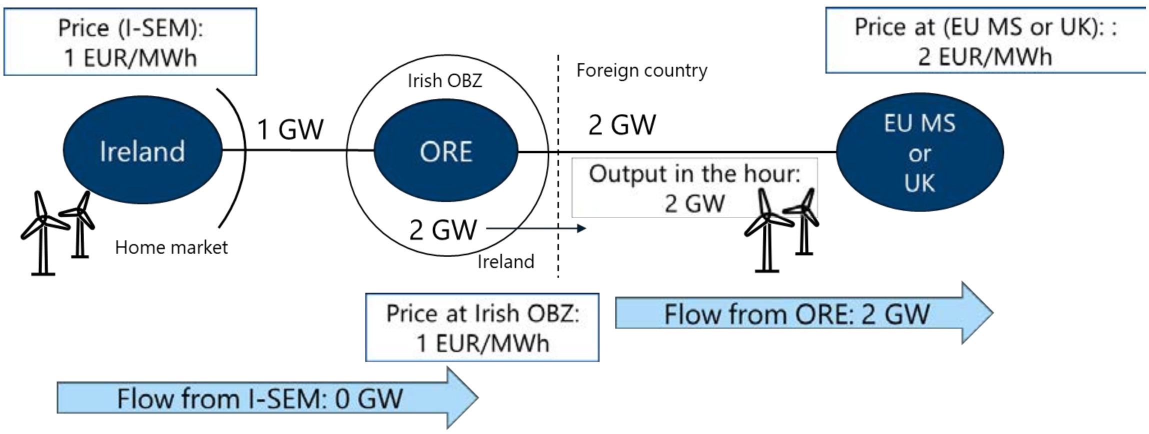


Energy flows from the low-price area to the high price area, but as ORE is not using all of transmission capacity, then part of the capacity on the cable is used as an interconnector between I-SEM and the neighbouring bidding zone.

Example 2: ORE generation at full capacity at an OBZ

In this variation of the first example, ORE generation is at full capacity (2 GW) and it thus uses the entire capacity on the transmission cable from the OBZ to the neighbouring country. In this case, there is no flow between the I-SEM and the OBZ.

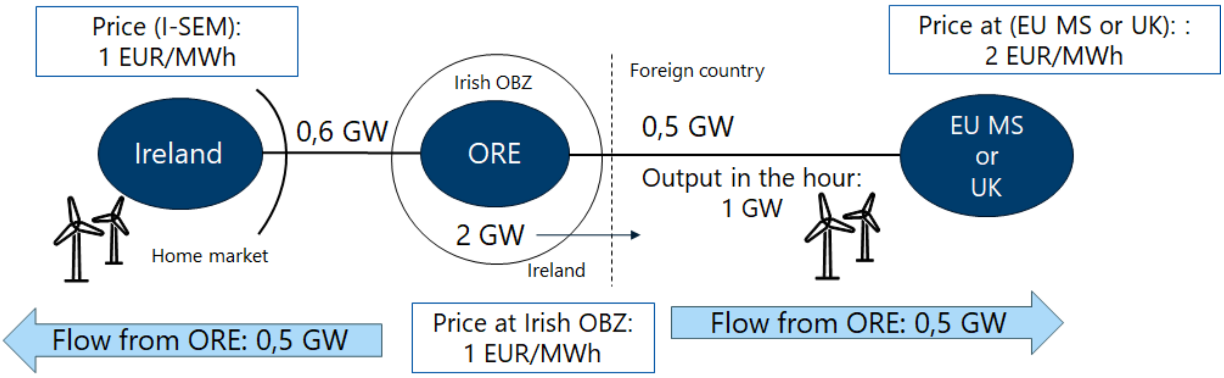
Figure 6: Example 2 - ORE generation at full capacity at an OBZ



Example 3: ORE generation flowing in both directions at an OBZ

ORE generation can also flow in both directions, as can be seen in the next example where transmission capacities are slightly modified: 0,6 GW between the I-SEM and the Irish OBZ, and 0,5 GW between this and the bidding zone in the neighbouring country. In this case, demand at the low-price zone determines the price offshore, as the line between I-SEM and the OBZ is uncongested. ORE flows to the bidding zone in the neighbouring country (0,5 GW) and to the I-SEM (0,5 GW) while 0,1 GW transmission capacity is not utilized.

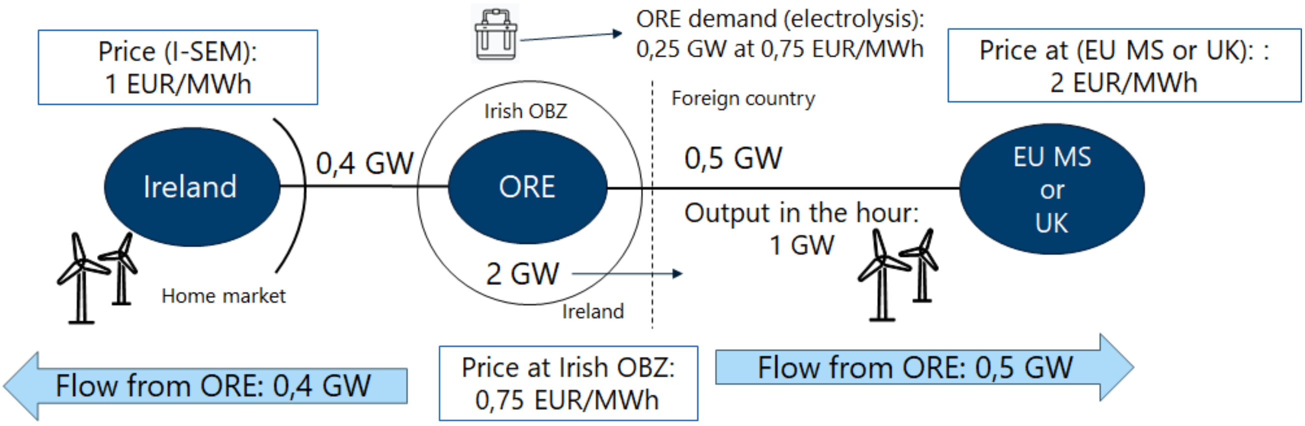
Figure 7: Example 3 - ORE generation flowing in both directions at an OBZ



Example 4: ORE generation and demand at the OBZ

In yet another variation, capacities on the transmission lines are now: 0,4 GW between the I-SEM and the Irish OBZ, and 0,5 GW between this and the bidding zone in the neighbouring country. One difference is that there is demand for ORE at the OBZ (a demand-side bid of 0,25 GW at 0,75 EUR/MWh). However, the price in the bidding zone in the neighbouring country is 2 EUR/MWh, so ORE generated will first flow in that direction. After this, it will flow to the I-SEM (0,4 GW) leaving the remaining output to be used at the OBZ: only 0,1 GW will be delivered at the OBZ.

Figure 8: Example 4 - ORE generation and demand at the OBZ

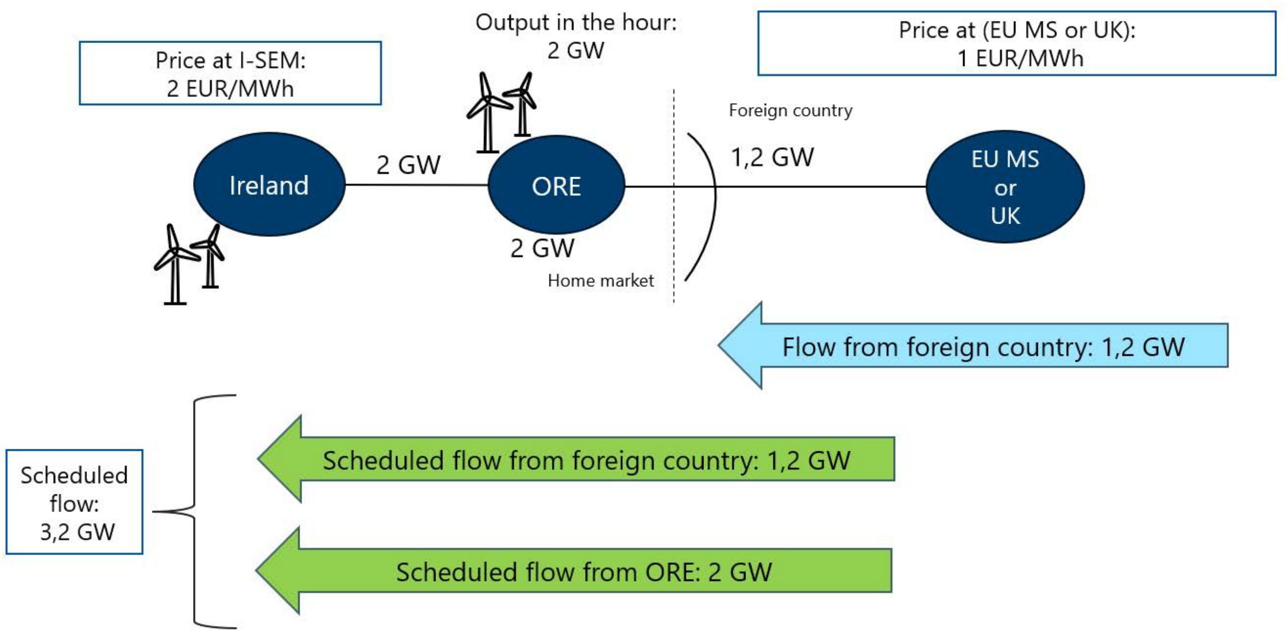


Comparing price formation in HM vs OBZ

Example 5: ORE generation in a HM

To fix ideas, example 5 shows ORE generation connected to the HM. In this example, ORE generation is compensated at the price in the HM, which in this case is 2 EUR/MWh. However, the line to the neighbouring country has 1,2 GW capacity only. Because the price at the I-SEM is 2 EUR/MWh, the market will schedule 2 GW from ORE generation *plus* the 1,2 GW from the neighbouring country. However, because the line to the I-SEM has only 2 GW capacity, scheduled generation will have to be reduced through redispatch measures to meet the physical constraints of the line. Assuming no demand in ORE, the redispatch will involve a reduction of wind (ORE) by 0,8 GW and an increase of generation in area I-SEM by 0,8 GW. Note that this amount of redispatch is the result of the day-ahead schedule minus the inflow from the foreign country: 3,2 GW – 1,2 GW = 0,8 GW. In other words, the TSO must allow the flow from the foreign country into the I-SEM, illustrating how ORE generation is bypassed by an import flow. For a stylized overview of the impact on redispatch and countertrade in a HM, see scenario 2 in Box 1 (comparison of countertrade in the HM and OBZ model).

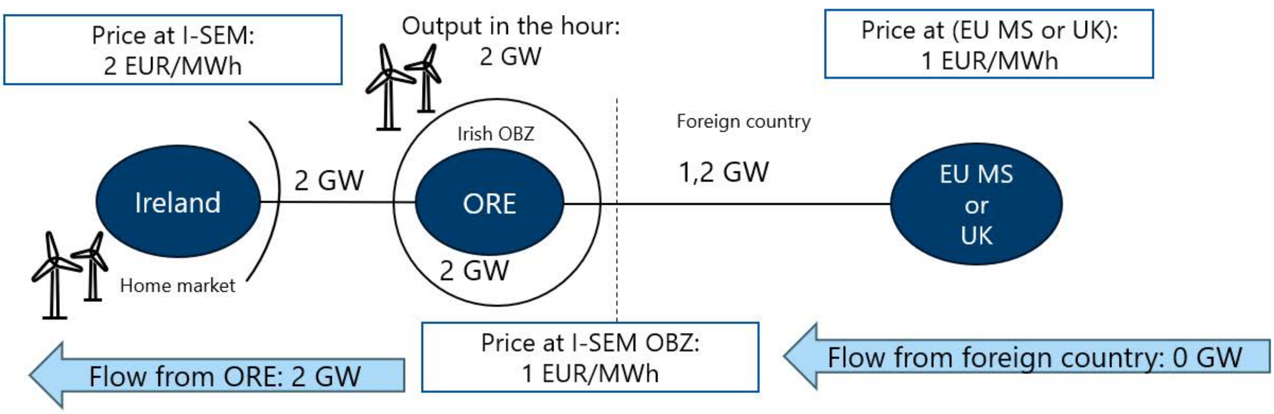
Figure 9: Example 5 - ORE generation in a HM



Example 6: ORE generation in an OBZ (counterfactual example)

In this counterfactual example, capacities and output are the same but the market setup is not. In this case, the physical flow and the scheduled flow coincide and there is no need to introduce redispatch measures to meet the physical constraints. In this case, the market setup reflects the physics, leading to better utilization of ORE generation in the location that requires it most. For a stylized overview of the impact on redispatch and countertrade in an OBZ, see scenario 1 in Box 1 (comparison of countertrade in the HM and OBZ model).

Figure 10: Example 6 - ORE generation in an OBZ (counterfactual example)



Producers operating under a HM approach area *physically* connected offshore but marketwise are assumed to be operating onshore in the same way as other onshore producers are. This has an impact on TSOs, which require implementing re-dispatch and countertrade measures to maintain balance.

1.1.3 Amendments to the EU regulatory framework

To avoid the deviation from the 70% rule and to make an efficient use of the infrastructure, one immediate solution is to assign all ORE generation to its own bidding zone, namely an OBZ. The main difference between hybrid projects operating in a HM and an OBZ is that under an OBZ configuration, all flows on the cable are cross-border and are therefore compliant with the 70% rule. In other words, OBZs reflect the physical reality more accurately than what the HM does. Not only will a price in an OBZ better reflect the geographical granularity of renewable energy production, but it will also internalize the structural congestion arising from limited transmission capacity to shore into the pricing mechanism.

Producers operating under a HM approach area *physically* connected offshore but marketwise are assumed to be operating onshore in the same way as other onshore producers are. This has an impact on TSOs, which require implementing re-dispatch and countertrade measures to maintain balance.

Although all involved stakeholders (TSOs, EU Commission and producers) coincide that implementing OBZs is the way forward, there still is an absence of clarity as to how and when will this take place.[5]

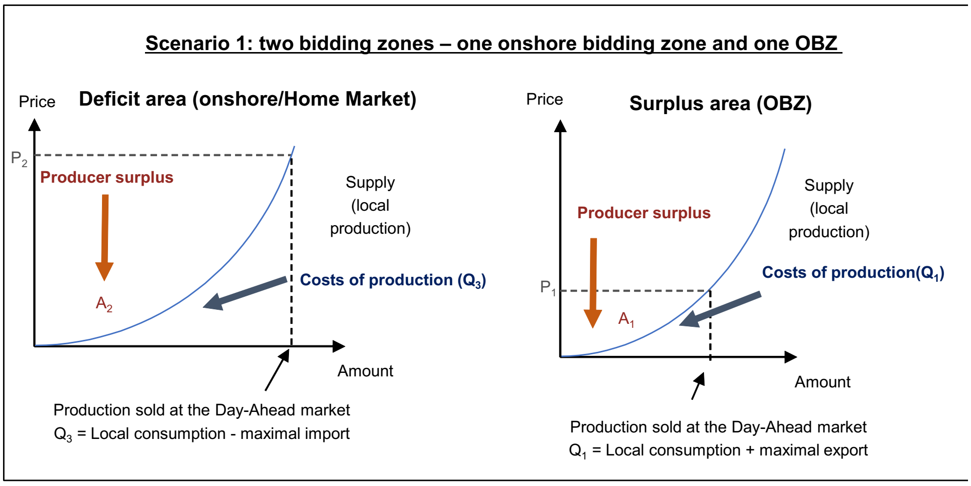
[5] ENTSO-E has expressed its favourable view towards OBZ in a position paper on Market and Regulatory Issues (ENTSO-E, 2020). Similarly, the EU Commission made it clear in its offshore renewable energy strategy that OBZs were its preferred approach (European Commission, 2020). Major developers like Ørsted have also expressed a positive view on this approach – see their White Paper "Regulatory Set-up for hybrid offshore wind projects" (Orsted, 2020). Not least, ACER and CEER have expressed an agreeing position to the main contents of EU's strategy in a "Reflection Note" (ACER & CEER, 2022).

Box 1: comparison of countertrade in the HM and OBZ model

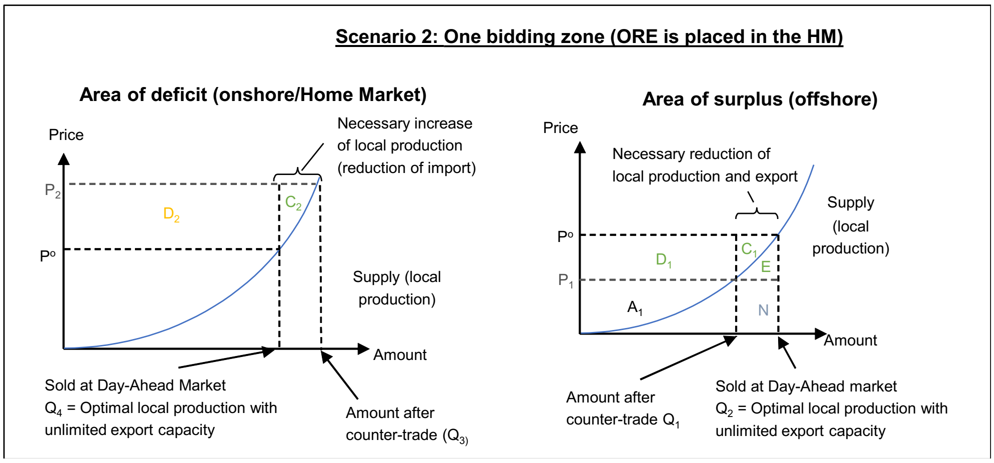
Why do redispatch and countertrade measures differ between a HM and an OBZ model?

To understand why do redispatch and countertrade measures differ between a HM and an OBZ model, it is useful to present a simplified case with only two areas being connected by a transmission line.

Scenario 1 (upper figure): in this case, it is assumed that the OBZ is the surplus area and that the line between this and the onshore bidding zone (the Home Market) is an interconnector between two different bidding zones. In the example, the OBZ is in surplus as it has more ORE generation than demand, which is either zero or small relative to generation. The deficit area is the onshore bidding zone (the Home Market). The interconnection between the OBZ and the home market is assumed congested, which means all transmission capacity is used and two different prices emerge, one onshore and the other at the OBZ. Note that this stylized example coincides with Example 6 in the section "Comparing price formation in HM vs OBZ".



Scenario 2 (lower figure): in the lower figure, ORE generation belongs to the onshore bidding zone (Home Market). The line between ORE generation and the shore is *internal* in the bidding zone. In the example, the line is congested which would lead to excess production not being transported to shore. To relieve this congestion, TSO engages in countertrading in the day-ahead market. In practice, onshore production needs to be increased while offshore it needs to be decreased. Before countertrade, onshore producers sell Q4 and ORE sell Q2. Note that this stylized example coincides with Example 5 in the section "Comparing price formation in HM vs OBZ".



The TSO compensates the ORE producer for reducing production offshore and obtain D1+C1+E. Onshore, the TSO pays C2 to increase production. This means that ORE generators are better off with the HM setup.

In this idealized setting, countertrading results in the same production pattern of generators in the two market setups. Total socio-economic net-benefit is the same in the two setups but required TSO intervention at the expense of congestion rent. Concerning consumer surplus, the opposite applies: consumers obtain a lower price (and larger surplus) in the deficit area in the HM solution relative to the OBZ setup.

Identified challenge: Bidding Zone Review process may require simplification

The existing regulatory framework establishes the conditions and process to conduct a bidding zone review (see box 1), but this process may become lengthy if concerned TSOs and Member States cannot agree on an emerging configuration. However, ACER and CEER note that establishing a new OBZ in the exclusive economic zone or territorial waters of one member state should not raise major issues, as the concerned member state is competent to deal with this matter.[6] Further development of hybrid projects and the increasing complexity may require both top-down regulation as well as a more coordinated approach to the operation of the offshore grid. This could, for example, entail the introduction of an Independent System Operator (ISO) to which several TSOs delegate the operation of the offshore grid.[7]

Identified challenge: Higher revenue risk for ORE developer than in radial projects

Another point of coincidence among stakeholders is that the implementation of hybrid projects in OBZs will lead to a higher price and volume risk exposure by ORE developers relative to the conventional radial connection to a HM. Regarding price risk, under an OBZ the ORE will be typically paid a lower price than if it were in the HM, as the capture price for ORE will coincide with the onshore price to which the line is not congested and the flow will be from a low-price to a high-price zone.

Concerning volume risk, producers may be curtailed in case of congestion or line outages. To mitigate the risk, re-distribution of congestion rents was initially proposed by the EU Commission as a revenue risk mitigating measure which would address re-distributional concerns.[8] However, this idea has been met with concern by other stakeholders (ACER and ENSTO-E) as this would amount to cross-subsidization, i.e. re-assigning income that would be lawfully earned by TSOs would be channelled to establishing risk measures that compensate ORE developers.

[6] The procedure to review bidding zones is outlined in the Capacity Allocation and Congestion Management Guideline (EU Regulation 2015/1222), Chapter 2 (European Commission, 2015).
[7] This idea is discussed in greater detail by ACER and CEER in their Reflection Note (ACER & CEER, 2022).
[8] See “Key Actions” on page 16 on the “EU Strategy to harness the potential of offshore renewable energy for a climate neutral future” (European Commission, 2020) where it is mentioned that article 19 (Congestion Income) of the Regulation 2019/943 on the internal market for electricity will be proposed to be modified.

Box 2: Bidding Zone Review according to the Capacity and Congestion Management Guideline (CACM-GL) and the Electricity Regulation (2019/943)

Bidding Zone Review according to the Capacity and Congestion Management Guideline (CACM -GL)

Who can initiate a bidding zone review (art. 32 and 34 of the CACM GL)?

- ACER, based on a technical report from ENTSO-E.
- Several regulatory authorities on the recommendation of ACER.
- The TSOs in a Capacity Calculation Region (CCR) together with all affected TSOs.
- A single regulatory authority or a single TSO after approval by its regulatory authority, if the determined bid area has an insignificant impact on the neighbouring TSO's system areas.
- Member States in a CCR.

*What must the initiator of the audit procedure specify (*Art. 32)?

- The "relevant region", i.e., the geographical area where bidding zone determination must be revised, as well as the adjacent geographical areas to be taken into account when assessing the impact.
- The participating TSOs and the participating regulatory authorities.
- If only one regulatory authority or one TSO initiates the procedure, it shall inform the TSOs or the authorities in the neighboring area.

What are the phases of a bidding zone review?

- <u>Phase 1:</u> TSOs develop methodology and prerequisites to be used in the review and propose alternative bidding zones for the assessment. The proposal is forwarded to the regulatory authorities, which must be able to request coordinated amendments within three months.
- <u>Phase 2:</u>
    - TSOs shall assess and compare the existing bidding zone and each alternative bidding zone using the criteria set out in Article 33.
    - TSOs carry out consultation and workshop on alternative bidding zones to the existing bidding zone.
    - TSOs shall submit a joint proposal to maintain or amend bidding zones to Member States and regulatory authorities within 15 months of the start of the audit.

The decision: The participating Member States or regulatory authorities have six months from the receipt of a joint proposal to each a decision.

<u>Source</u>: Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management (European Commission, 2015).

Bidding Zone Review in the Electricity Regulation (2019/943)

Article 14(7) of the Electricity Regulation establishes that upon identification of structural congestion by a TSO and approval by the National Regulatory Authority (NRA), the Member State can either establish action plans to alleviate the congestion or review and amend its bidding zone configuration. These decisions must be notified to both the EU Commission and to ACER.

<u>Source</u>: Regulation (EU) 2019/943 on the internal market for electricity (European Commission, 2019).

1.2 Energy modelling evidence

The introduction and development of a meshed offshore grid has been analysed from a research and development perspective and energy systems modelling has played a central role in many of the projects developed so far. With an energy system planning perspective in mind, many of these models investigate the medium and long-term evolution of energy systems.

Based on carbon-neutral scenarios, the deployment of ORE as well as other technologies to achieve these goals is analysed. In the following section, we present a focused non-exhaustive review of such studies, which facilitate identification of some of the most relevant pros & cons.

1.2.1 North Sea Offshore Network – Denmark (NSON-DK)

Background

NSON DK, a research project developed by a consortium of Danish institutions in cooperation with Germany, Norway and the UK[9], analysed how the deployment of off offshore wind will affect the Danish power system in the short, medium and long term.

One of the central questions the study investigated was whether a dedicated offshore grid infrastructure connecting hubs in the North Sea would be advantageous compared to the traditional radial connection of offshore wind parks.

Objective, methodology and scenarios

The open-source energy system Balmorel was employed to investigate two alternative scenarios with 2030 and 2050 as time horizons:

- **Project-based offshore wind development:** Offshore wind generation is connected radially to shore and point-to-point interconnectors between countries were allowed.
- **Integrated offshore grid scenario:** The emergence of a meshed offshore grid configuration is allowed as a competing alternative to the configuration in the project-based scenario (radial only and point-to-point interconnectors). Under this scenario, offshore wind can be connected to hubs, hub-to-hub interconnectors are possible and hubs are connected to shore.

2030 and 2050 were the analyzed time horizons. Geographically, Denmark, Norway, Great Britain, Netherlands, and Germany were modelled in detail. The objective of the optimization was to determine the least cost energy demand subject to a variety of technical constraints.

Key messages and results

- **Allowing for the development of an offshore meshed grid is effective for offshore wind deployment:** In the integrated offshore scenario, 28% of offshore wind farms are hub-connected by 2050, and if transmission line investment costs are doubled, this figure drops to 18%. However, total offshore wind deployment is always higher in the integrated offshore development scenario than in the project-based scenario, which allows for radial connections only.
- **If transmission line costs double, onshore solar PV deployment will always be higher regardless of the scenario, but allowing for a meshed grid will always make offshore wind deployment more cost-efficient:** In
- Table *2*, solar PV deployment increases in both scenarios as the cost of building hubs and interconnectors increases. However, results show that deploying offshore wind is always more cost-

[9] The project's official website is: North Sea Offshore Network project - NSON-DK (nson-dk-project.dk)

effective when a meshed grid is allowed than when only radial interconnections are allowed (94,4 GW vs. 85,9 GW), which also means that onshore wind deployment is lower, indicating that building offshore wind with a meshed grid is more cost competitive than building onshore wind.

Table 2: VRE capacity deployment in the NSON-DK scenarios (2050)

Technology	Project-based offshore		Integrated offshore	
	Main	**2x line cost**	**Main**	**2x line cost**
Solar PV	179,3	190,2	180	187,7
Offshore wind	95,8	85,9*	99,7	94,4**
Onshore wind	113,3	114,7	108,4	107,9
Total VRE (GW) in 2050	**388,4**	**390,8**	**388,1**	**390**

Source: Koivisto & Gea-Bermúdez (2018).

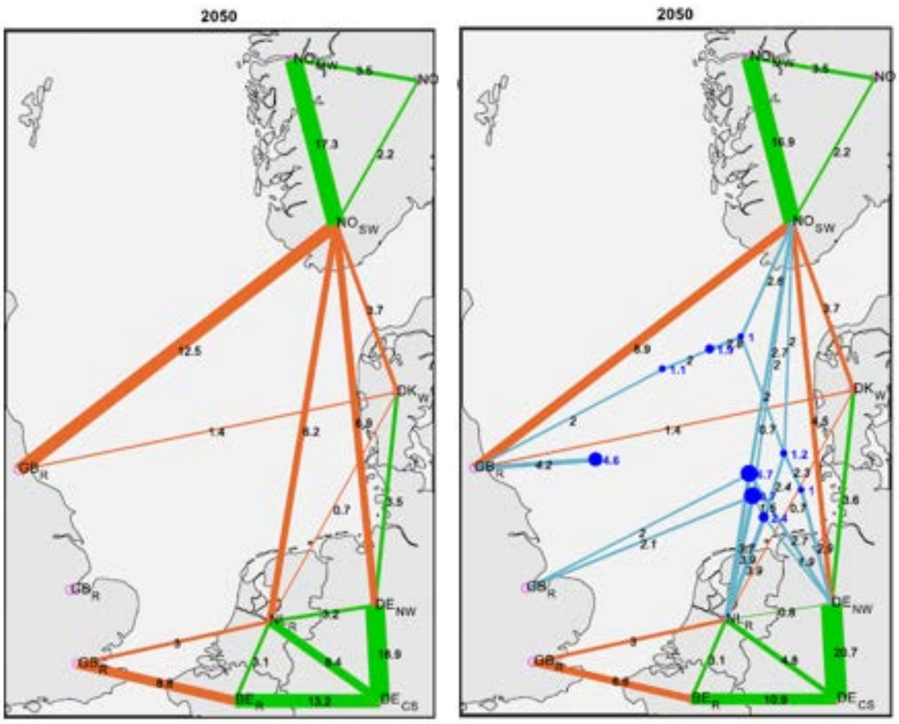
Note: * Indicates that 28% of capacity was hub-connected, ** Indicates that 18% of capacity was hub-connected

Geographically (see Figure 11) the value of a meshed grid can be observed in: see

- The value of connecting Norway to other countries. The benefits of combining its flexible hydro generation to the increasing VRE generation shares in other countries are evident. In addition, connection of continental Europe to GB is desirable under the two scenarios.
- The value of a meshed offshore grid can be observed through: i) the interconnections between connecting Norway and Great Britain, as well as Norway and Netherlands and Germany via offshore hubs; ii) interconnecting large offshore German developments to the Nrtherlands, Great Britain and Norway.

- In 2050, Germany has the majority of hub-connected offshore wind, while GB has the larger offshore wind capacities.

Figure 11: Transmission infrastructure development in the two NSON-DK scenarios (2050)



Source: Koivisto & Gea-Bermúdez (2018)

Note: Left: interconnector development in the project-based scenario; Right: transmission infrastructure development in the integrated offshore grid scenario

1.2.2 North Sea Wind Power Hub (NSWPH) Pathway Study - 2021

Background

The aim of the NSWPH Pathway Study was to identify what the build out of the electricity and hydrogen system under a variety of scenarios could look like.[10] The main focus was on onshore and offshore infrastructure challenges related to the roll-out pathway of the first and following hub-and-spoke projects.

The integration of large-scale offshore wind in the North Sea together with the benefits of international cooperation among EU countries were among the key elements of the Pathway Study.

Objective, methodology and scenarios

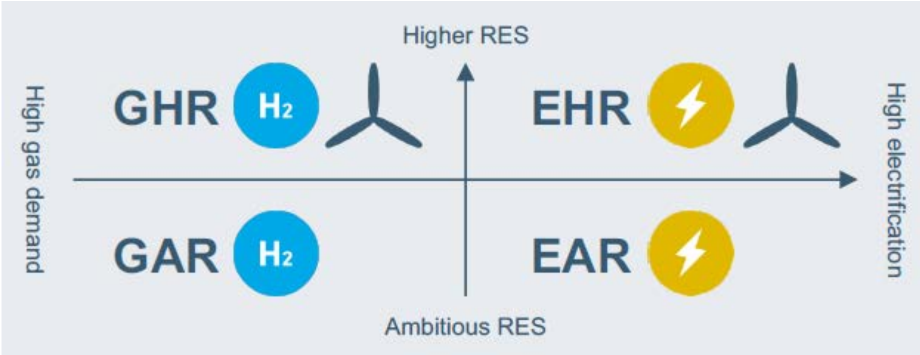
A comparison of two rollout pathways:

- **International Coordinated roll-out (ICRO)** in which offshore wind farms can only connect radially to their respective home country, versus
- **National Incremental Roll Out (NIRO)** in which offshore wind farms can connect radially to their respective home country, to other wind farms and to neighbouring countries formed the basis of the analysis. These pathways were compared across four different scenarios:

[10] The North Sea Wind Power Hub (NSWPH) Consortium is formed by Energinet, Gasunie and TenneT, three European TSOs who are promoting research and analysis to attain climate ambitions. Their publications are available at: https://northseawindpowerhub.eu/

- **GAR** (high gas demand and ambitious renewable energy supply- RES), which was used as the base scenario for the study
- **EAR** (high electrification and ambitious RES)
- **GHR** (high gas demand and higher RES)
- **EHR** (high electrification and higher RES)

Figure 12: Four scenarios in the NSWPH Pathway Study



Source: NSWPH Programme (2022)

The energy system simulation software Balmorel was used to conduct investment optimization of the four scenarios and the temporal scope was 10-year time-steps between 2030 and 2050. Geographically, the model resolution covered 21 European countries (Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland).

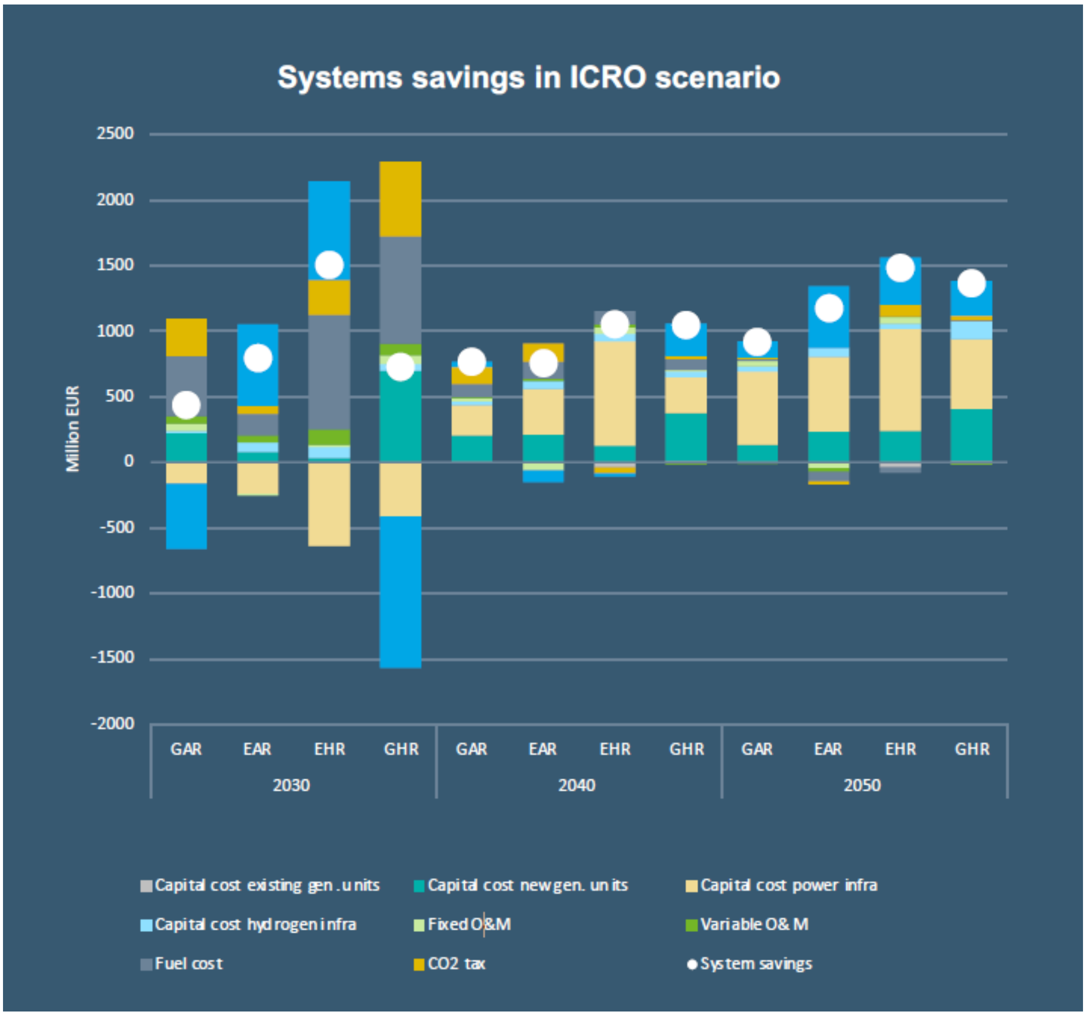
As the link between hydrogen and electricity are particularly relevant for the future energy system and, the model optimized both power and hydrogen assets. Total installed power generation capacities, annual electricity and hydrogen demand were exogenously fixed, and the following assets were optimized:

- Power transmission
- Power storage
- Hydrogen based power generation (G2P)
- Electrolysers
- Hydrogen transmission
- Hydrogen storage

Key messages and results

- **The ICRO pathway shows overall energy system benefits relative to NIRO in the range of 3-6%.** These arise from the following:
    - More offshore infrastructure reduces the need for onshore investments.
    - Reduced fuel and CO2 costs from dispatchable power units.
    - Less generation fleet expansion.
    - Reduced non-EU hydrogen import requirements.

Figure 13: ICRO vs. NIRO system savings breakdown – NSWPH



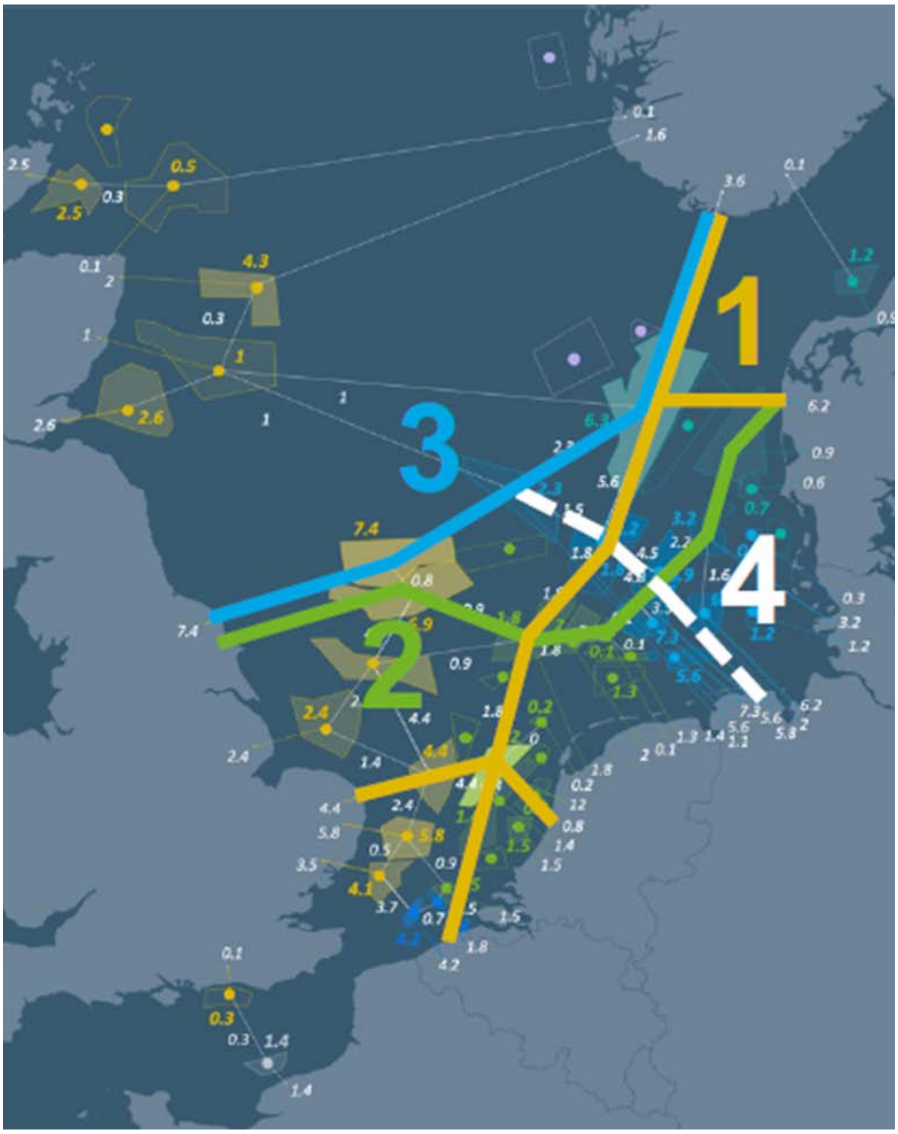
Source: NSWPH Programme (2022)

- **Geographically**:
  - The Netherlands benefits from transit flows of electricity and hydrogen.
  - Germany benefits from hydrogen imports and lower investments in production units.
  - Denmark benefits from lower investment in infrastructure and imported electricity while investing more in flexible production units.

- **The ICRO reveals the emergence of strong connections between the UK and the EU and four key routes**:
  - A **North-South corridor** from Norway via Denmark, Germany and the Netherlands towards the UK DK-GER-NL towards the UK and Belgium.
  - An **East- West corridor** connecting Denmark via Germany and Netherlands to UK.
  - A **Northern corridor** connecting Norway via Denmark and Germany to the UK.
  - A **German branch** is seen in all cases as part of the system.

Route 1 could be combined with route 2 as a possible additional branch. Route 1 can also be extended towards Belgium and the UK. The most likely routes depend on the offshore wind roll-out plans.

Figure 14: Emerging corridors in the ICRO – NSWPH



Source: NSWPH Programme (2022)

One identified limitation of the study is that power generation capacities are exogenously defined by the TYNDP's Distributed Energy scenario, which could risk confounding political ambitions with political decisions is always present.

1.2.3 Economic Appraisal of Potential WindConnector Developments[11]

Background

This study prepared by Pöyry (2019) for the Dutch TSO TenneT, evaluated the possibility of developing a hybrid interconnector with GB as an extension of the connection to shore of the planned 4 GW capacity to be developed at the IJmuiden Ver region.[12] The study aimed at identifying the economic benefits – both quantitative and qualitative - of combining connection to shore with cross-border transmission between GB and Netherlands.

[11] Pöyry Management Consulting (UK) Limited (2019), "Economic Appraisal of Potential Wind-Connector Developments".

[12] When the report was published (October 2019), Netherlands had planned to deliver 11 GW of total installed capacity by 2030, of which the IJmuiden Ver region was planned to have 4 GW capacity. As of May 2023, Netherlands has raised the target to 21 GW by 2030-2031 with a 6 GW capacity to be deployed at the IJmuiden Ver region (Netherlands Enterprise Agency, 2023b).

A driving factor for proposing the WindConnector was the identification by ENTSO-E of further benefits arising from the integration between Netherlands and GB by 2040. These benefits are due to; i) the expected price differences between the two markets, ii) the need for flexibility to optimize renewables integration, iii) the need to improve the overall security of supply in periods when high demand coincides with low electricity generation.

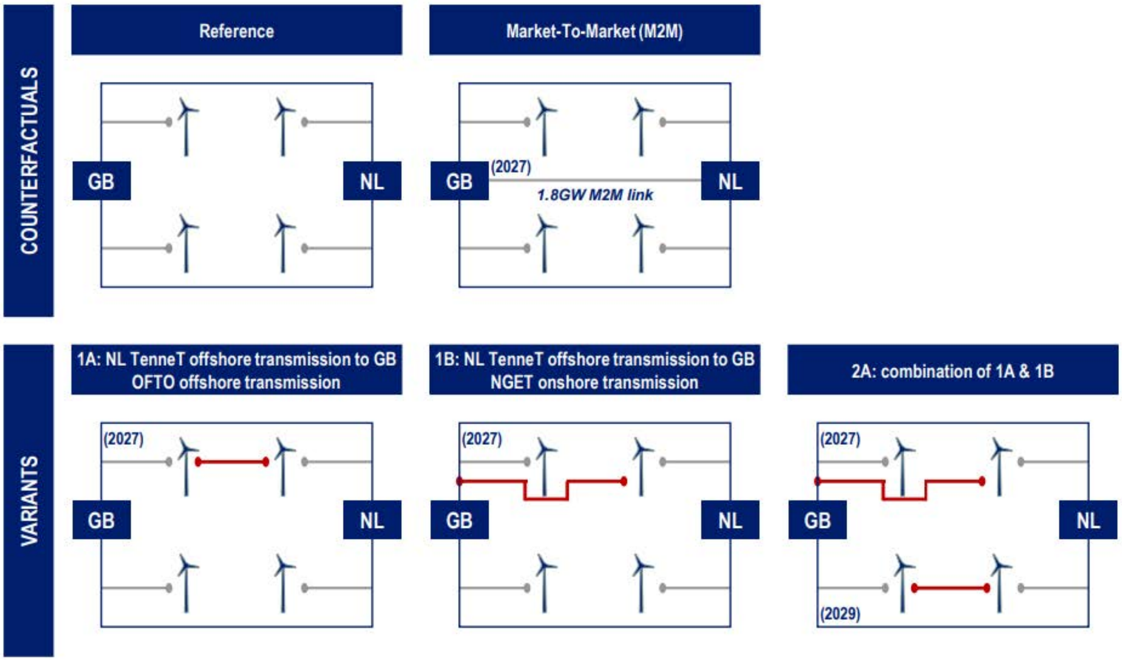
Objective, methodology and scenarios

Four configurations were assessed against a reference case with no interconnections (see

Figure 15):

- **Market-to-Market (M2M)**: Point-to-point interconnector between the two markets.
- **Variant 1A (offshore-offshore)**: WindConnector between TenneT offshore transmission to GB OFTO offshore transmission. In this case, windfarm connections provide links to either shore.
- **Variant 1B (onshore GB – offshore NL)**: WindConnector between TenneT offshore transmission to the onshore GB transmission. In this case, Dutch windfarm connections provide the connection to the NL shore.
- **Variant 2A**: Combination of the above two variant options in parallel.

Figure 15: WindConnector configurations



Source: Pöyry (2019)

Key messages and results

- **Relative to the reference case (no interconnection between countries, only radial connections to shore), there are positive net socio-economic benefits for all considered configurations (see Figure 16):**
  - o Net socio-economic benefits are highest under variant 2A, with an estimated 2207 million EUR in Net Present Value (NPV) and the largest benefits accruing to consumers.

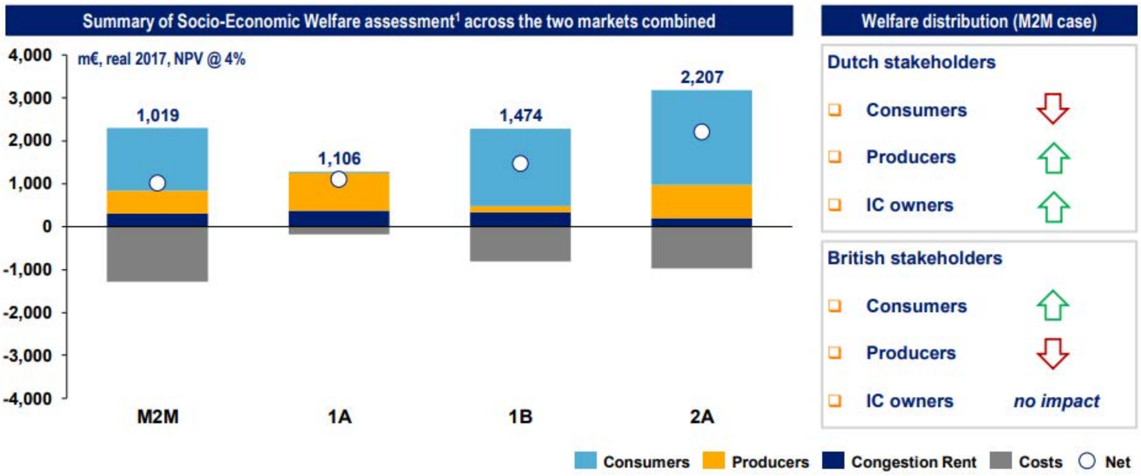
- The second largest net socio-economic benefit was estimated for variant 1B with an estimated NPV of 1474 million EUR. However, in this case, producers' surplus becomes much lower than in variant 2A, yet consumers still earn the largest benefits.

- The third largest socio-economic benefit was estimated for variant 1A (NPV: 1106 million EUR), but under this variant it is producers who earn most of the benefits.

- The fourth largest socio-economic benefit (NPV: 1019 million EUR) was estimated for the M2M configuration, where a point-to-point interconnector is established in addition to radially connected ORE.

- There are benefits for the wider region, as consumers that are interconnected with either Netherlands or GB experience lower wholesale electricity costs.

Figure 16: WindConnector socioeconomic assessment relative to the reference case



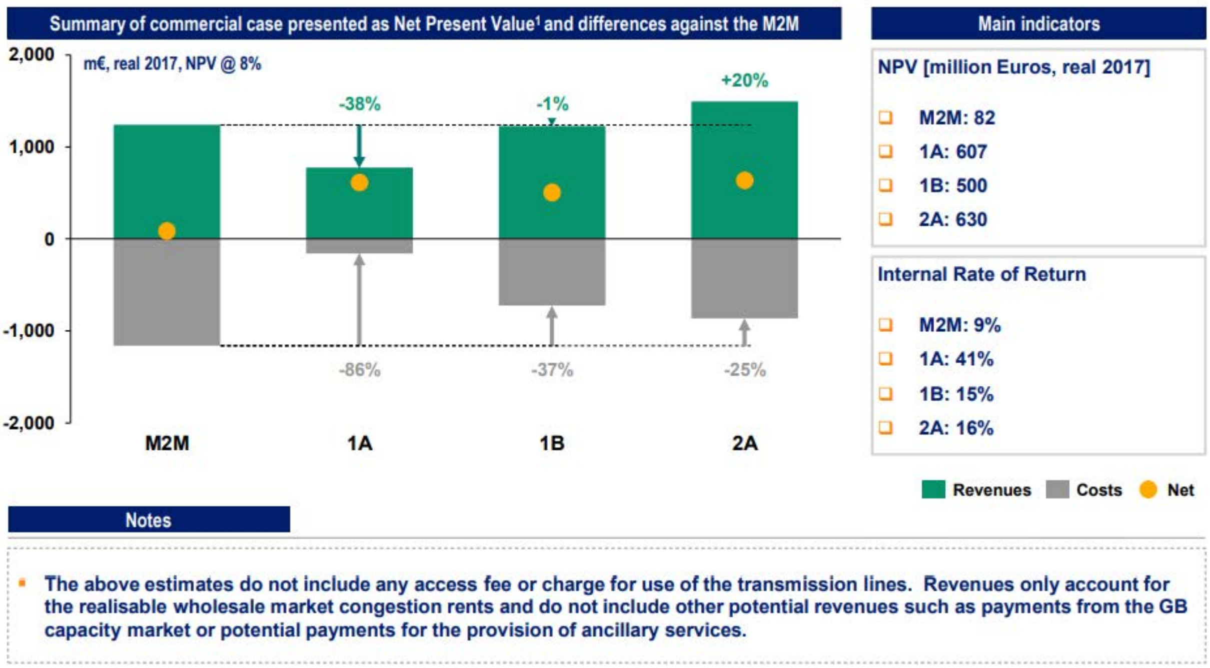
Source: Pöyry (2019)

- **The estimated net socio-economic benefits arise from:**[13]
  - **Affordability**: A reduction in average wholesale price differences, with most flows in the NL-GB direction. Similarly, a reduction in Dutch renewable energy support scheme (RESS) and capacity payments in GB.
  - **Sustainability**: Lower thermal generation costs and reduced C02 emissions.
  - **Reliability**: Increased access to balancing capacity and complementarity in the power generation patterns.
- **The commercial case for the infrastructure assets reveals that reduced infrastructure costs outweigh all possible reductions in congestion rents relative to a standard point-to-point interconnector:**
  - Configuration 1A has the higher internal rate of return (IRR) with 41%. In this case, congestion rent falls by 38% relative to the M2M case, yet costs decrease by 86%

[13] The report by Pöyry (2019) notes that the overall socio-economic benefits will not be affected by the introduction of the 70% rule (see page 10 on this topic). However, the introduction of OBZs could have important re-distributional impacts among the involved stakeholders.

- Configuration 2A has the second highest IRR with 16% and in this case congestion revenue increases by 20% but costs fall only by 25%. This is also the configuration with the highest NPV (630 million EUR).
- The higher utilisation rate of the shared assets are critical for costs reductions.

Figure 17: WindConnector commercial case assessment



Source: Pöyry (2019)

1.2.4 Study on Baltic Offshore Wind Energy Cooperation under Baltic Energy Market Interconnection Plan (BEMIP)

Background

With a substantial but heterogenous potential for offshore wind power development in the Baltic Sea, the need to investigate ways to improve offshore infrastructure utilization was identified.

In this study prepared by COWI and partners for the European Commission (2019b), the main goals were to gather information on the potential for offshore wind power in the Baltic Sea as well as the opportunities and obstacles to its development, identifying possible benefits and barriers to regional cooperation and coordination of offshore wind power development. In addition, this study proposes a roadmap for the implementation of a coordinated offshore wind strategy for the region.

Objective, methodology and scenarios

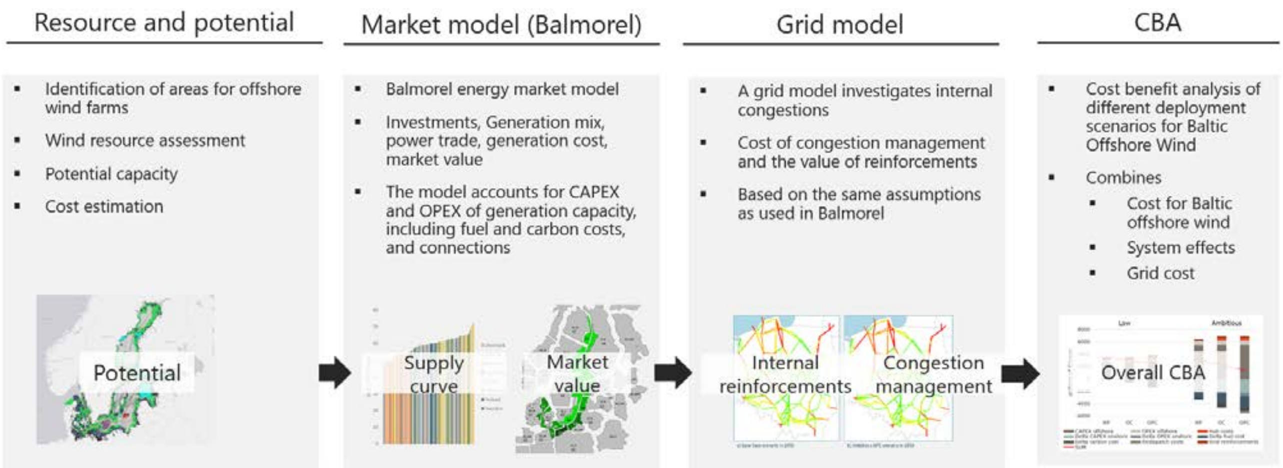
The process to quantify the role and value of Baltic offshore wind power in the European power market under the BEMIP project can be summarized in the following points (see Figure 18):

1. **Assessment of wind resource and potentials:** At this stage, areas for offshore wind development were identified and resources were quantitatively assessed to produce potential capacities and estimations.
2. **Energy market modelling:** An energy systems modelling tool (Balmorel) was employed to simulate the energy system of the BSA and several surrounding countries in Europe. The energy

market model determined the optimal investments in generation and transmission taking CAPEX, OPEX, fuel and carbon costs into consideration.

3. **Grid modelling:** Based on the same assumptions used by the energy market model, a grid model investigated internal congestions in the grid which ultimately allowed quantifying the need for congestion management.
4. **Cost Benefit Analysis (CBA):** At this stage, several deployment scenarios for offshore wind deployment in the BSA were analysed. The CBA took direct offshore wind costs, system costs as well as grid costs into consideration.

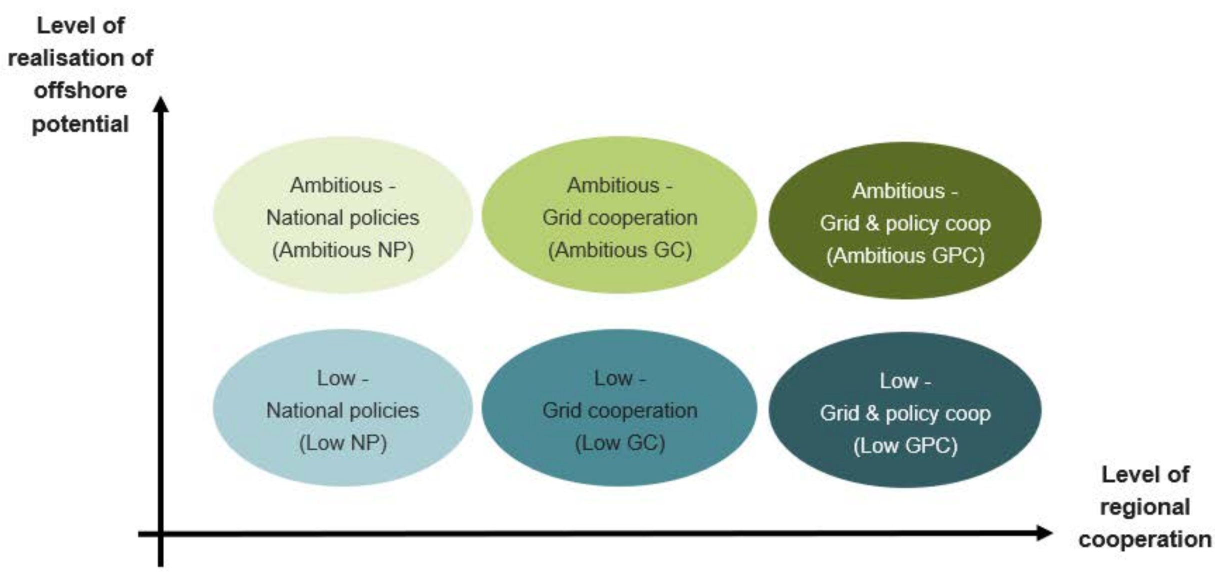
Figure 18: Evaluation process (BEMIP)



Source: COWI (2019b)

To assess how coordinated efforts can enhance the efficiency of offshore wind power development in the Baltic region of the region, six different scenarios were utilized at the energy market modelling stage, reflecting three levels of regional cooperation (horizontal axis in **Error! Reference source not found.**) and two ambition levels for offshore wind deployment (vertical axis in **Error! Reference source not found.**). The time horizon for the analysis was 2030 and 205.

Figure 19: Assessed scenarios in the BEMIP study.



Source: COWI (2019b)

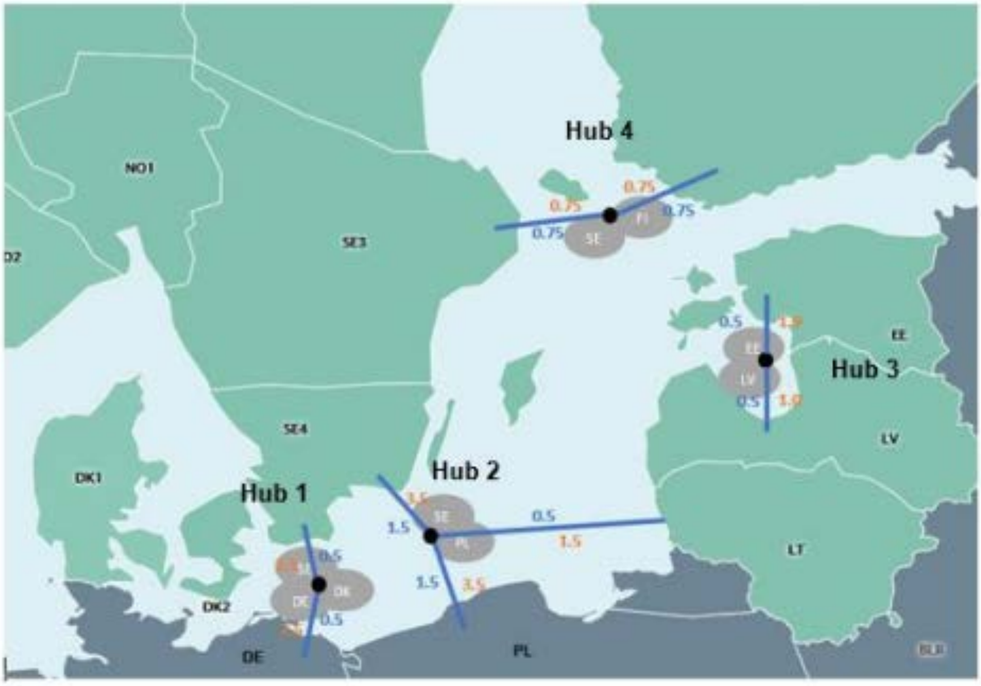
- **The three degrees of Regional Cooperation were:**

- **National Policies (NP)**: National targets are met through the use of national resources only, and developed offshore wind is radially connected to the respective national grid. A fixed capacity of Baltic offshore wind deployment is defined for each of the individual BEMIP countries. Each country deploys offshore wind generation along this fixed trajectory, but the market model endogenously selects the individual sites. The scenario reflects the main approach used in offshore wind power deployment today.
- **Grid Cooperation (GC)**: Approximately 45% of the national targets are achieved via the development of four exogenously selected offshore wind power hubs connected to two or three BEMIP countries (see Figure 20). The hubs are hybrid interconnections, as they serve the dual purpose of connecting ORE to shore and interconnecting bidding zones. Hubs are placed in both the southern and northern parts of the Baltic Sea and connections are made to all countries in the region. Hub design is not static across scenarios as stronger connections are included for the 2050 scenarios compared to 2030. The specific wind farms connected to the hubs also vary slightly between the low and ambitious scenarios Remaining national targets (approximmately 55%) are reached nationally as in NP.[14]
- **Grid and Policy Cooperation (GCP)**: In this scenario, the four advanced offshore hubs from the grid cooperation scenarios are also established. Unlike the GC scenario, in this case capacity not connected to the hubs is distributed by the model across the entire Baltic Sea in order to achieve regionally cost-effective deployment of the same overall level of offshore wind power capacity reflecting policy cooperation. This change allows the model to select the most attractive offshore wind farm sites, namely those that provide the highest earnings relative to the investment made, from across the whole of the Baltic Sea.

- **The two ambition levels were:**
  - **Low Scenario**: Continuation of current expectations and trends (17 GW of offshore wind capacity in 2050 in the BSA).
  - **Ambitious Scenario**: Ambitious but achievable pathway to higher offshore wind capacities (32 GW of offshore wind capacity in 2050 in BSA).

Figure 20: Offshore hub configurations in the Baltic Sea

[14] Hub 1 includes Germany, Sweden and Denmark, hub 2 is between Sweden, Poland and Lithuania, hub 3 is between Estonia and Lithuania and hub 4 is between Finland and Sweden. Hubs 1 and 2 were initially configured in the Baltic InteGrid project: https://interreg-baltic.eu/project/baltic-integrid/



Source: COWI (2019b)

Key messages and results

- **Cooperation on offshore wind power development and long-term planning can reduce total system costs. However, establishing cooperation can be costly:**
    - Cost savings result mostly from lower onshore CAPEX and OPEX as well as reduced fuel and carbon costs. Figure 21 show total system costs in the analysed scenarios relative to the Low NP scenario. Note that in Figure 21, negative numbers reflect cost reductions while positive numbers reflect increases. For example, in 2030 offshore CAPEX is 1341 million EUR/year higher than in the Low NP scenario.
    - Offshore wind deployment through hubs makes offshore wind more efficient in terms of system costs. To observe this, in Figure 21 note that the categories “Delta CAPEX onshore”, “Delta OPEX onshore”, “Delta Fuel Cost” and “Delta carbon cost” decrease relative to the Low NP scenario.
    - Net benefits can be achieved in the long run rather than in the short to medium term when initial investments take place and regional cooperation are initiated. For example, in Figure 21 total system costs are 399 million EUR/year higher than the Low NP under the Ambitious GC scenario in 2030. In contrast, by 2050 there are net benefits of 790 million EUR/year.
    - International cooperation can bring about efficiencies relative to national strategies that only target the best sites within their Exclusive Economic Zones (EEZ). Therefore, high neighbouring RES ambitions linked with the potential of international policy and grid development cooperation enable cost-efficient ambitious deployment levels by 2030 onwards.

Figure 21: Total and net costs in BEMIP scenarios

	Low		Ambitious		
2030	GC	GPC	NP	GC	GPC
CAPEX offshore	102	84	1115	1341	1343
OPEX offshore	1	1	231	232	233
Hub costs	85	85	0	206	206
Delta CAPEX onshore	24	-41	-604	-562	-704
Delta OPEX onshore	11	25	-261	-250	-272
Delta fuel cost	-36	25	-151	-276	-267
Delta carbon cost	-24	-25	-82	-227	-174
Redispatch costs	-49	-74	61	-65	-92
Grid reinforcement	0	0	0	0	0
SUM	114	80	309	399	273

	Low		Ambitious		
2050	GC	GPC	NP	GC	GPC
CAPEX offshore	218	379	2701	3209	3200
OPEX offshore	0	0	373	374	378
Hub costs	210	210	0	454	454
Delta CAPEX onshore	-80	-55	-1664	-1819	-2186
Delta OPEX onshore	-41	115	-510	-499	-586
Delta fuel cost	-234	-1006	-894	-1642	-1917
Delta carbon cost	-51	-264	-221	-505	-465
Redispatch costs	-397	-167	-198	-398	-579
Grid reinforcement	0	0	0	36	36
SUM	-375	-788	-413	-790	-1665

Source: COWI (2019b)

- **Regional cooperation on advanced offshore wind power hubs (GC scenarios), could reduce total system costs by 400 – 1600 million €/year in 2050 (see Figure 21),** compared to the Low NP scenario, due to more efficient offshore wind deployment and the better integration of renewable generation capacity due to the better interconnection. In parallel, the achievement of national renewable energy targets can be realized at lower costs. Consequently, the resulting increased interconnection capacities in cooperative scenarios support a better utilization of onshore renewable sources.

- **The timing of investment decisions but also anticipatory decisions is expected to be essential.** Sensitivity analysis on the GC scenarios showed that the total generation costs are reduced if only the two of the most profitable hubs are established before 2030. Deploying the four hubs in 2030 resulted in increased costs, meaning that both ambition levels and the cooperation on hubs should be carefully considered. Furthermore, by taking offshore wind power deployment into account early on in grid planning in the context of a shared long-term vision can produce substantial cost and efficiency gains. The identification of crucial investments in generation and grid infrastructure, along with appropriate measures and incentives to realize these appears to be a vital step for the future. Joint financing mechanisms for cross border grid infrastructure among TSOs could help overcome cost-benefit distribution barriers.

- **Regional policy cooperation without hub and international interconnection cooperation is also found profitable, but the inclusion of advanced hubs resulted in the least system costs in 2050.** Nevertheless, regional cooperative solutions on tendering and support mechanisms, on grid connection charges and cost sharing mechanisms, and on integrated regional grid planning, are important pre-requisites for harnessing the offshore wind power potential of the region.

- **The integrated nature of the transmission network and the potentially important role of cross-border projects implies that many of the necessary investments will give rise to costs and benefits spread across multiple member states**. Better mechanisms for the appropriate sharing of these costs and benefits are therefore likely to be needed. A summary of the barriers to a solid development of international cooperation identified by the study is provided in Figure 22:

Figure 22: Barriers to international cooperation (BEMIP).

National policy mechanisms	• National policy mechanisms (with some exceptions) do not provide adequate support for offshore wind power projects • Multinational projects often effectively excluded
Grid connection regimes	Differences in grid connection regimes for offshore wind power distorts the "merit order" of sites and projects and reduces the potential benefit from cooperation
Mechanisms for sharing grid costs	Lack of regulatory mechanisms for aligning costs and benefits, creating disincentives for mutually beneficial grid projects that involve more than one nation
Licensing procedures and data quality	• Onerous and opaque licencing procedures increase developers' costs • Missing data, poor data deter developers and increase developers' costs • Complicated licensing procedures for multinational projects
Insufficient regional grid planning	• TSO-level cooperation on offshore grid planning not sufficiently supported • No standing group tasked with considering network solutions related to offshore wind hubs

Source: COWI (2019b)

1.2.5 North Seas Offshore Energy Clusters (NSEC) study - 2019[15]

Background

In the North Seas Offshore Energy Clusters study prepared by Roland Berger (2019) for the European Commission, 18 potential hybrid projects were initially assessed. The 18 projects are in four North Seas regions (see

Figure *23*): German Bight, Dogger Bank, Irish Sea/North Channel and the UK-Netherlands-Belgium cluster.

Figure 23: Proximity of assessed projects in the NSEC study

[15] Roland Berger GmbH (2019), "How to reduce costs and space of offshore development : North Seas offshore energy clusters study"

Source: Roland Berger (2019)

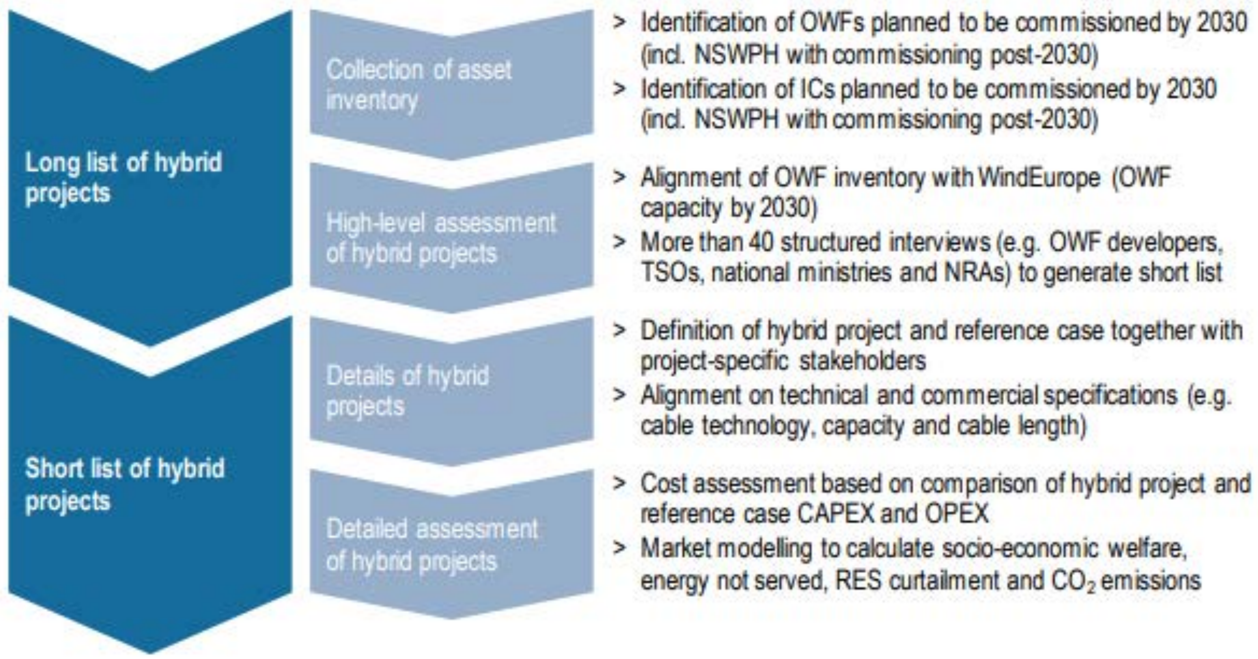
Of these 18 projects, the 10 most promising ones were shortlisted based on a four-dimensional feasibility check with technical feasibility, cable development needs, neighbouring offshore wind farm alignment and stakeholder complexity as selection criteria.

Of the 10 shortlisted projects, the five most feasible were assessed against their conventional counterfactual in terms of capital expenditures, lifetime operating expenses and socio-economic welfare (SEW). Further aspects, such as the EU energy policy targets were also considered. Finally, the study provides recommendations on the implementation of future hybrid projects.

Objective, methodology and scenarios

The study started by drawing up a long list of hybrid projects, based on an inventory of OWFs and interconnectors. This considered all OWFs in the Irish, UK, Belgian, Dutch, German, Danish and Norwegian EEZs that are currently operational or due to be commissioned by 2030. Additionally, the study considered the possible generation and transmission infrastructure of the NSWPH, even though this hybrid project has a commissioning horizon beyond 2030. The pathway towards the shortlist and detailed assessment of the selected projects, as summarized by the study, can be seen graphically in Figure 24:

Figure 24: Methodology sequence for the NSEC study



Source: Roland Berger (2019)

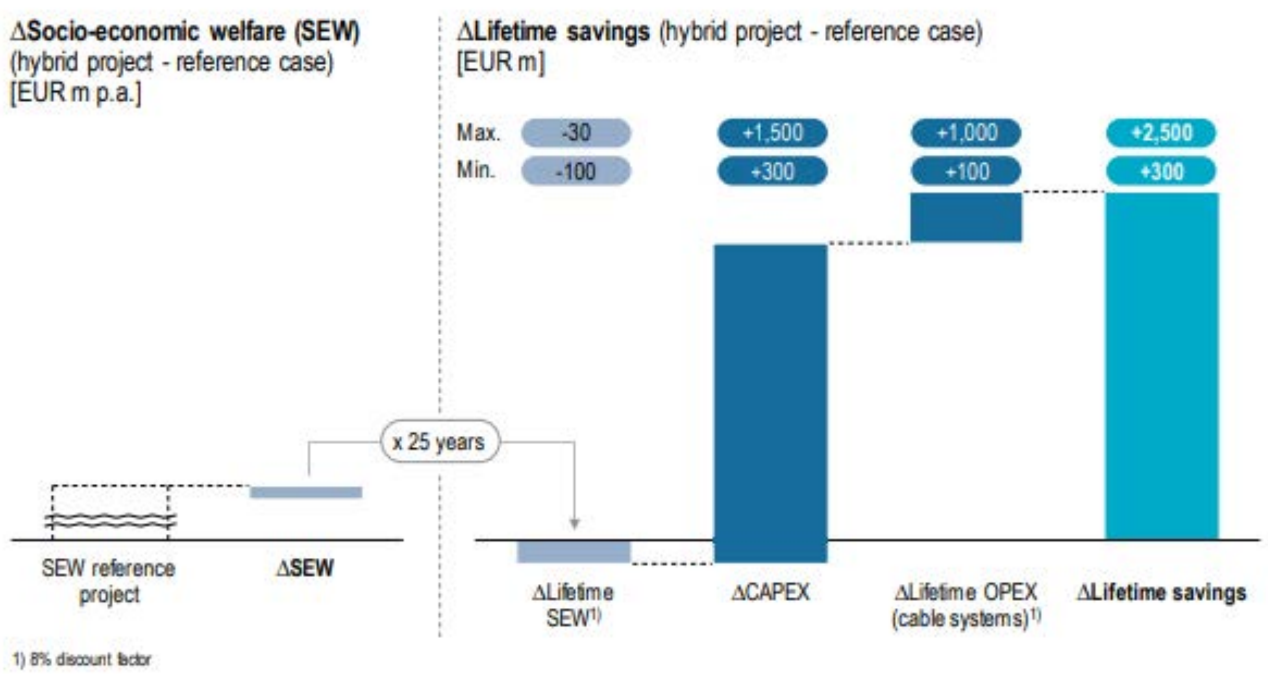
The cost assessment is developed in terms of upfront experienced CAPEX, discounted OPEX to evaluate the overall socio-economic welfare over a 25-year operational period. In terms of market modelling, the METIS model of the Joint Research Centre of the European Commission was utilized. Hourly optimization of the European power system, minimizing the variable cost of generation while respecting technical and economic operating constraints was the backbone of the study.

Key messages and results

- **Five projects show potential for cost savings between 300 - 2500 million EUR, which corresponds to 5-10% of the total project cost (see Figure 25):**
  - **The "IJmuiden Ver to UK" hybrid project**: A Dutch OWF in the IJmuiden Ver area is linked to the UK electricity market via an interconnector and to the Dutch electricity market. Savings of approximately 400 million EUR driven by the elimination of approximately 65 kms of cable and a converter station can be obtained relative to the reference case where only a point-to-point interconnector is built.
  - **The combined grid solution between IJmuiden Ver to Norfolk**: The UK and Dutch electricity markets are linked by an interconnector between a British OWF in the Norfolk area and a Dutch OWF in the IJmuiden Ver area. The hybrid configuration yields savings of approximately 720 million EUR resulting from the elimination of 130 km of cable and two onshore converter stations.
  - **COBRA Cable hybrid project**: in this project, a German OWF is connected to both Netherlands and Denmark via the already operational COBRA cable between Denmark and Netherlands. This hybrid tie-in project yields savings of approximately 390 million EUR relative to the reference case, as the hybrid setup saves 200 km of cable and a converter station.

- **The DE OWF to NL project**: in this project, a German OWF is radially connected to the Netherlands only yielding savings of about 260 million EUR, which result from the elimination of 115 km of cable, as the distance to the Dutch shore is closer than to the German shore.[16]
- **North Sea Wind Power Hub (NSWPH)**: OWFs in the Dutch, German and Danish EEZs are connected to the Dutch, German and Western Danish electricity markets via a hub in the Dogger Bank area of the North Sea. The hub features cable connections to the Netherlands, Germany and Denmark which can function as export cable systems and as interconnectors and yields 25-year lifetime savings of 2500 million EUR relative to the reference case.

Figure 25: Lifetime savings potential by hybridization in the NSEC analysis.



Source: Roland Berger (2019)

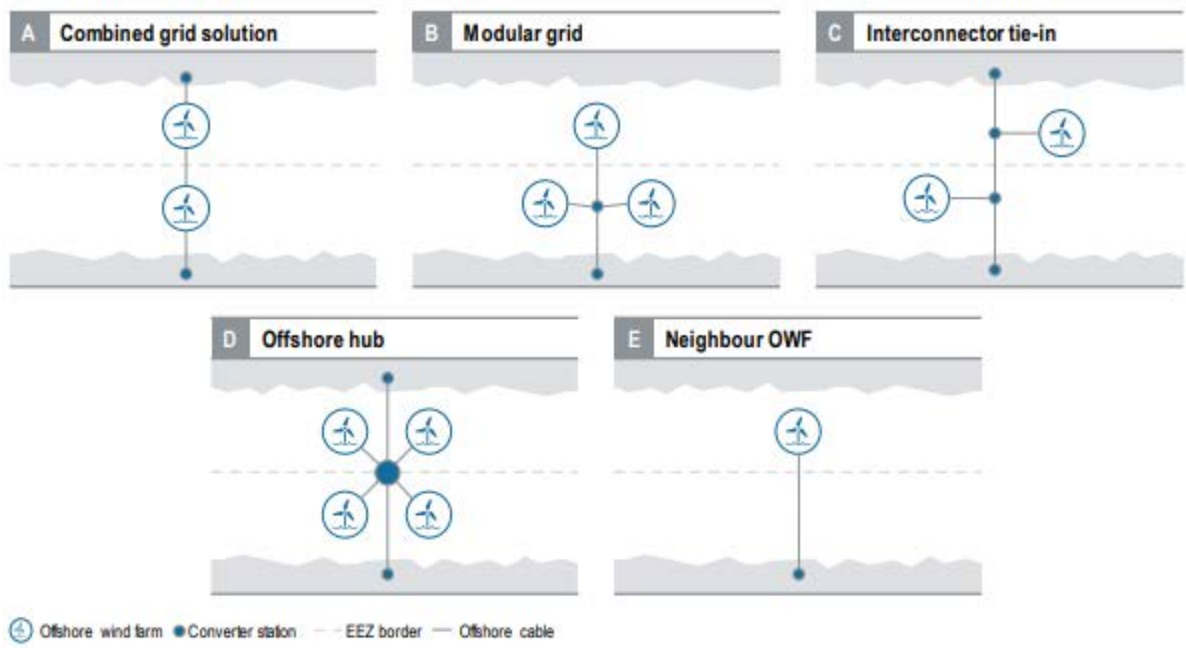
- **Each project is unique in terms of the costs and benefits, which creates a need for a case-by-case evaluation which calls for a series of considerations:**
  - Although hybrid projects reflect a positive socio-economic welfare, this is consistently (yet slightly) lower than the SEW of the reference cases. This is because hybrid projects utilise cable systems for more than one purpose, which in modelling terms results in lower benefits to the involved parties.[17]
  - The difference between SEW in the hybrid case relative to the reference case is consistently small and when extrapolated to a typical project duration cost saving exceed the difference in SEW by more than a factor of 10.
  - The pillars of the identified lifetime savings are:
    - Reducing kilometers of the evacuation line, i.e. the ORE connection to shore

[16] In a strict sense, this is not a hybrid project as it involves only a radial connection to the Dutch shore from a German OWF. This also is an example of an export-only ORE generation facility.
[17] An example of this situation arises with an interconnector tie-in (an OWF connection to shore via an interconnector). The modelling result will be reduced interconnection capacity as well as more frequent curtailment relative to the reference case, which will ultimately result in a lower SEW.

- Reducing kilometers of interconnector cable
- Reducing the number of onshore and offshore substations
- Realising less expensive operations and maintenance services for offshore installations

- **Hybrid setups differ and provide different ways to produce net benefits (see Figure 26):**

Figure 26: Hybrid project concepts in the NSEC study



Source: Roland Berger (2019)

- **Interconnector tie-in concepts**, which connect an OWF to shore via an interconnector. In this case, cost savings are realised if the OWF is located at a distance of more than 50km from shore and connected with HVDC.
- **Combined grid solution concepts,** which connect two offshore wind farms (OWFs) in different exclusive economic zones (EEZs). In a similar fashion to the interconnector tie-in, cost savings are realised if the OWF is located at a distance of more than 50km from shore and connected with HVDC[18].
- **Neighbor OWF concepts**: which connect an OWF located in the EEZ in one country to the shore of another one. In this case, cost savings are realized via cable savings, meaning the hybrid project must include a connection to a closer onshore connection point than in the reference case. In this case, the avoidance of onshore grid reinforcement can be advantageous, depending on the specific project setup.
- **Offshore hub concepts,** which connect multiple OWFs to at least two markets via an offshore hub. In this case, cost savings are realised through three main channels:

[18] In both tie-in and combined grid solution concepts, the higher investment cost in HVDC technology is justified when there is a longer distance, as power losses are significantly reduced relative to HVAC solutions. In contrast, with near-shore ORE a lower investment cost in HVAC technology is justified, as this does not involve a converter station.

- o By reducing the CAPEX of substations. These can be placed on the hub, removing the need for their own offshore foundations, which are costly.
- o Second, the larger space available on an offshore hub allows for larger substations with cheaper designs.
- o Third, offshore hubs allow for the cost-effective maintenance of equipment, accommodation of staff and provision of port and helicopter infrastructure, decreasing OPEX. However, these depend on the distance between an offshore hub and the closest onshore site from where maintenance can be provided. The combined CAPEX and OPEX savings must outweigh the additional cost of building an offshore hub.

➢ **Modular grid concept**: in this concept, multiple OWFs located in different EEZs, connect to shore through a single evacuation line. In the analysis, no modular grid concept-based hybrid project was found and therefor no evaluation of benefits and costs in this context could be made.

- **Hybrid projects face significant legal regulatory and other barriers:** the study identified 16 critical barriers for the implementation of a hybrid project have been identified – 13 of them applicable in the 5 selected projects analysed in the NSEC study. [19]

Figure 27: Effects of identified barriers on the five identified projects in the NSEC study

	IJmuiden Ver to UK	CGS NL to UK	NSWPH	COBRA Cable	DE OWF to NL
1. Uncertainty about responsibility for project development	■	■	■	■	■
2. Uncertainty about regulation deriving from jurisdiction over cross-border cable systems	■	■	■	■	■
3. Uncertainty about market arrangements	■	■	■	■	■
4. Uncertainty about hybrid cable system classification	■	■	■	■	□
5. Failure of developers to align planning across assets and countries	■	■	■	■	■
6. Uncertainty about responsibility and rules to provide access to maritime space for OWFs (location selection, site pre-investigation, tender execution)	□	□	□	■	■
7. Uncertainty about responsibility and rules to provide access to maritime space for OWFs (tender design)	■	■	■	■	■
8. Discrepancies in responsibilities and requirements for balancing 1)	□	□	□	□	□
9. Discrepancies in priority dispatch regulation 1)	□	□	□	□	□
10. Discrepancies in curtailment regulation and compensation 1)	□	□	□	□	□
11. Lack of regulated revenues for anticipatory investments	■	■	■	□	□
12. Uncertainty about the applicable RES subsidy scheme	■	■	■	■	■
13. Limited engagement of public stakeholders	■	■	■	■	■
14. Uncertainty regarding the UK market	■	■	□	□	□
15. Disproportionate allocation of costs and benefits across involved stakeholders	■	■	■	■	■
16. Uncertainty about legislative regime for power-to-gas and related infrastructure	□	□	■	□	□

■ Relevant barrier for project □ No relevant barrier/relevance uncertain for project 1) Part of CEP negotiations, mitigation to be developed based on CEP results (if required)

Source: Roland Berger (2019)

1.2.6 North Sea Grid

Background

The North Sea Grid project was completed in 2014 by a consortium of partners for the EU's Intelligent Energy Europe programme. Building on previous studies,[20] the project investigated why despite the economic, environmental, and technical advantages of integrated solutions (such as hybrid projects) these projects were

[19] Project-specific action plans to mitigate the barriers were outlined in the study. Overall, top-bottom regulation from the European Union may be necessary to mitigate for some of the barriers.

[20] Mainly the Offshore Grid project. See 3E (2011)

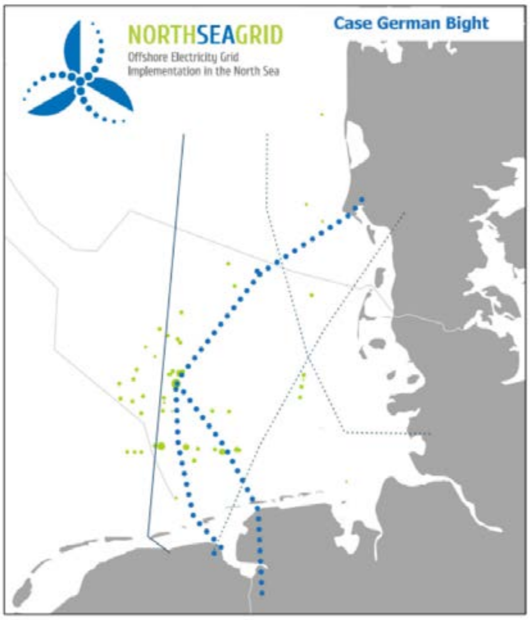
not being built. Three concrete case studies illustrated the barriers present and motivated recommendations for practical solutions to financial and regulatory barriers to the development and construction of these projects.

Objective, methodology and scenarios

The North Sea Grid was carried out through the following steps:

- **Selection of concrete case studies** which allow implementing specific, transferrable recommendations. The selected case studies were:
  - The **German Bight** (see Figure 28) where:
    - A German OWF is connected to both Germany anf Netherlands
    - Another German OWF is connected to Denmark
    - Hub-to-hub interconeection is present

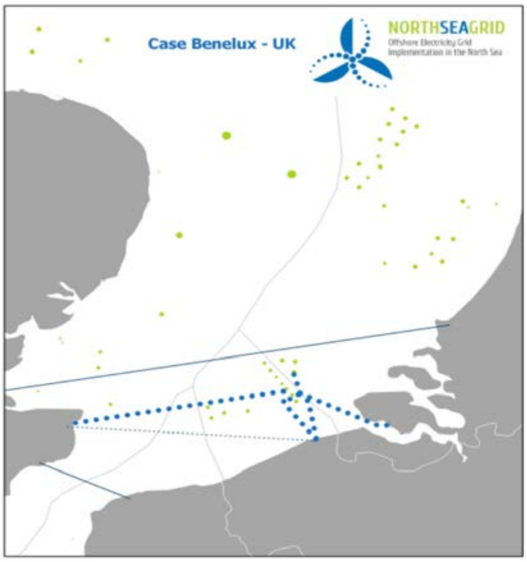
Figure 28: German Bight case (North Sea Grid project)



Source: Flament et al. (2014)

  - The **UK-Benelux** where**:**
    - Belgian OWFs are connected to two platforms (alpha & beta)
    - Interconnection from UK to Belgian alpha
    - Dutch OWF is connected to Belgian beta
    - Interconnection between Belgian beta to Netherlands

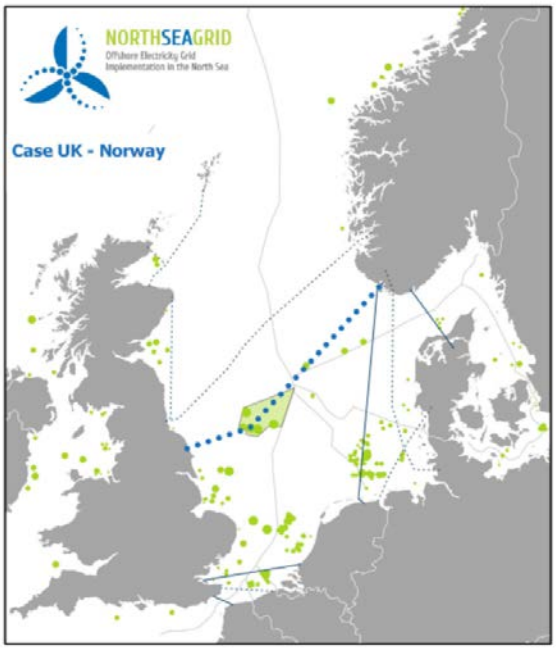
Figure 29: Case UK – Benelux (North Sea Grid project)



Source: Flament et al. (2014)

- **UK-Norway** where:
  - There is a large UK OWF
  - The largest part of OWF is connected to UK
  - Remaining capacity is connected to Norway

Figure 30: Case UK-Norway



Source: Flament et al. (2014)

- **Multiple scenario analysis:** the study evaluated costs and benefits under multiple scenarios including several sensitivity analyses.
- **Risk assessment:** which entailed a probabilistic risk assessment of the estimated costs and benefits.
- **Cost-benefit allocation:** the study proposed a cost-benefit allocation among different stakeholders.

Key messages and results

- **Integrated project development leads to less material requirements and costs, as well as higher utilization rates**. Overall, the risks are overall similar to isolated developments, which results in a higher net present worth.
- **The NPV of the net benefits is positive for the three case studies**, as shown in Table 3. However, in one of the cases (the UK-Benelux case) the CAPEX of the integrated case is higher than in the base case, which indicates that benefits outweighed the costs over the project lifetime. In both the German Bight and UK-Benelux cases, the benefits are driven primarily by the increased level of interconnection between the North Sea Grid countries.

Table 3: Key data of the case studies (North Sea Grid project)

	NPV of net benefits (Million EUR/year)	Base case CAPEX (Million EUR)	Integrated case CAPEX (Million EUR)
German Bight	1213	2962	2608
UK-Benelux	650	1911	2348
UK-Norway	350	8794	8249
All integrated	2292		

Source: Flament et al. (2014)

- **Higher renewable penetration increases the benefits, while lower fuel costs, carbon prices and demand response reduce them**. This is reasonable as renewables increase flexibility requirements, which can be provided by fossil sources as well as by demand response.
- **Cross-border projects may be beneficial overall, but their benefits are likely to be distributed asymmetrically between the concerned countries**. The study evaluated three possible methods:
  - **Conventional**: Under this method, congestion rent is shared on the basis of the equal share principle.
  - **Louderback**: Infrastructure costs are divided over countries depending on their attributable (direct) costs plus a share of the common costs.
- **Positive net benefit differential (recommended as strating point for negotiations):** This is the main recommended method from the study. According to this method, net benefits are determined at country level. Negative net benefits for 'losers' are compensated by a contribution from 'winners' with a positive net benefit in accordance with a pre-set compensation rule.[21]

1.2.7 Summarizing Pros & Cons of hybrid interconnections

As can be observed from the variety of studies cited in the previous sections of this report, hybrid projects are a precursor to an emergent European offshore meshed grid.

On the cost side, there is a potential for efficiency gains resulting from the common usage of material requirements which ultimately reduce both CAPEX and OPEX. Benefits in terms of less onshore grid RES deployment, which reduces reinforcement needs as well as a more efficient deployment of ORE also accrue to the parties involved in a potential hybrid project. However, the complexity of these projects requires increased

[21] The method is part of ACER's Recommendation on Cross-Border Allocation (ACER, 2015).

coordination efforts both at the technical and political levels. Furthermore, the current status of the EU regulatory framework in which there are missing specific provisions, tend to create uncertainty relative to the more conventional approach to ORE development, which is characterized by radial connections to the domestic network in a HM design. Table *4* discusses the main pros & cons identified.

Table 4: Summary of pros & cons of hybrid interconnections

Pros	Cons
The main benefits from combining cross-border interconnection with transmission to shore (hybrid interconnections) include the following benefits: • Reduced CAPEX needs for transmission network development from an overall system perspective. • More efficient infrastructure use. This can be measured in terms of the higher utilisation rates of transmission assets. • Additional flexibility in power trading among the participating networks, i.e. trade can compensate for the usual fluctuations in RE production. • Hybrid projects may constitute the starting point for later expansion into a meshed offshore grid. For example, a hybrid project may later evolve into a configuration such as the hubs and spokes design. • Improved socioeconomic welfare in contrast to counterfactual conventional (radial) reference cases. • Potential for reduced ORE curtailment, which translates into a more effective utilization of produced renewable energy. • More efficient dispatchable generation: hybrids with ORE operating in an OBZ reflect the physical conditions in a more accurate manner and thus provide incentives for an efficient dispatch. • Regulatory compliance: hybrids operating under an OBZ meet the requirements of the 70% rule established in EU regulation. • Balancing of cross bidding zone electricity price differences. • Increased security of supply. • Lower environmental, community and societal impacts.	Hybrid projects are also associated with a high degree of complexity, costs, and barriers. Identified cons are: • The regulatory setup is more complex compared to the establishment of point-to-point interconnectors, as more parties may be involved, and more processes need to be coordinated. • Higher uncertainty to offshore wind developers in terms of: iii) revenue risk relative to the Home Market design approach. Under an Offshore Bidding Zone (OBZ) design, the price in that zone will normally be the least of the prices in the two adjacent zones connected to the OBZ. This reduces the revenue for the wind power developer. Revenue may also be affected if the evacuation line is congested. iv) the impact from expanding hybrid projects to offshore hubs: the revenue profile of an ORE producer changes when more competitors join. • Required changes to the regulatory framework and market design configuration: hybrid projects are not compliant with the 70% rule and the absence of priority dispatch under a HM design. This motivates the introduction of OBZs, which requires regulatory changes. • Cross-border cost and benefit allocation may constitute an issue among the involved stakeholders. Both benefits and costs may accrue asymmetrically to the parties involved requiring negotiation and agreements. • The timing of investment decisions and capacity deployment is of the essence. Thus, the uncertainty of parallel developments is high. • Post-Brexit issues:

	iii) The EU legal framework is not valid in the UK. iv) Insufficient clarity with respect to the implementation of the Trade and Cooperation Agreement (TCA) between the EU and UK may prevent an efficient utilization of the infrastructure. This includes but is not limited to the loose market coupling arrangements.

1.3 Best practices for hybrid projects: evidence from selected jurisdictions

1.3.1 Selected jurisdictions

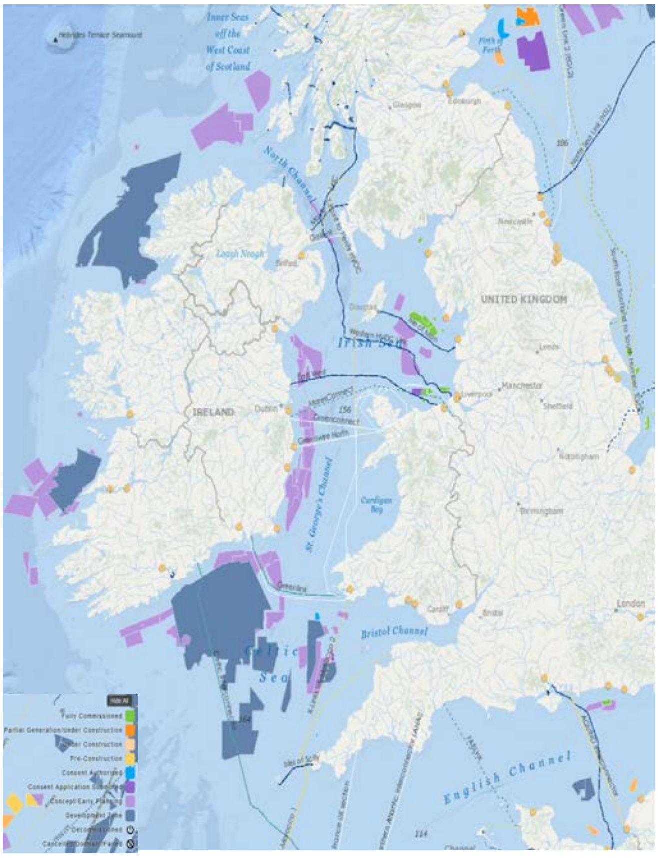
To understand the best practices for hybrid projects, three jurisdictions were selected. The selection was partly based on an alignment with the remaining deliverables of the project on Ireland's transition to a plan-led regime, as there was interest in studying experiences with *common* relevance to the topics addressed by each deliverable. With regards to the development of a hybrid interconnection policy for Ireland, the selected jurisdictions provide relevant insights and lessons for Ireland:

- **Denmark** is a fellow EU Member State with significant ORE ambitions, including two planned energy islands, hybrid interconnectors with neighboring countries and participation in the NSWPH. Denmark is also pioneering country in relation to both ORE and hybrid projects, including the only operational hybrid interconnector (the KFCGS) between Denmark and Germany. Furthermore, Denmark also has an interconnector with the UK, which could provide relevant insights for Ireland with regards to the operation of an interconnector with the UK in a post-Brexit context.
- **Netherlands** is another fellow EU Member State with a well-developed offshore wind policy framework. Not only is the Netherlands part of the NSWPH, but has concrete hybrid projects under discussion and negotiation with the UK. As an EU Member State with existing interconnections to the UK, the Dutch case is also relevant for Ireland.
- **The UK**: The geographical proximity of Ireland with the UK means that an important part of the ORE resources of both countries are found in the *same* geographical areas (Figure 31). The Irish Sea, the North Channel and the Celtic Sea contain many areas where ORE developments are underway. This means that any relevant analysis for Ireland ORE must include the UK, as this will likely be the most natural partner for a potential hybrid project. In addition, the UK and Ireland already share interconnections and the UK is at present Ireland's only link with the rest of Europe.[22] Furthermore, the UK already has initiated a series of regulatory and policy initiatives to develop hybrid interconnections, which in the UK's jurisdiction are referred to as Multi-Purpose Interconnectors (MPIs), that may be relevant for Ireland.[23]

[22] The Integrated Single Electricity Market (I-SEM) which operates in the Island of Ireland is connected to the GB market through the East-West interconnector (500 MW) and through the Moyle interconnector (500 MW) between Northern Ireland and Scotland. In a strict sense, Ireland is currently connected to the rest of Europe only through the GB market. Two interconnectors, the 500-MW Greenlink (with the GB market) and the 700-MW Celtic interconnector (with France) are expected to be commissioned by 2024 and 2026, respectively.

[23] Ofgem (2023) proposes a broader category of Offshore Hybrid Assets (OHAs) which encompass MPIs and Non-Standard Interconnectors (NSIs).

Figure 31: ORE development and interconnectors in Ireland and the UK



Source: 4C Offshore

1.3.2 Defining comparison criteria

To compare each of the selected countries, the following criteria were defined. Specific research questions define the information that is sought under each criterion:

- **Criterion 1- Offshore and onshore transmission planning framework:**
  - ➢ How does the coordination between offshore renewable energy developers, transmission system operators and state agencies work during the planning process?
  - ➢ How do hybrid projects emerge during the planning process? Are projects “hybrid by design” or are these “hybridysed”?
- **Criterion 2 - International coordination:**
  - ➢ How does cross-border coordination emerge in the process?
  - ➢ What are the institutions involved? Does cooperation happen exclusively through TSOs? How are state agencies involved?
- **Criterion 3- Financing of transmission assets:**
  - ➢ What are the financing and cost recovery methods considered for hybrid projects?
- **Criterion 4- Operation and remuneration:**
  - ➢ What are the specific conditions for operation and remuneration of hybrid projects in the given jurisdiction?

  - Are hybrid projects expected to operate under OBZs or under a HM?

- **Criterion 5 - Government policy towards hybrid projects:**
  - Is there a specific policy framework for hybrid projects in the specific jurisdictions?
  - What is the energy policy stance regarding hybrid projects including state aid mechanisms?
- **Criterion 6 – Perception towards EU policy and regulation:**
  - What are the main issues and barriers present in the EU policy and regulatory framework for hybrid projects?
- **Criterion 7 - Perceived challenges:**
  - What are the perceived overall challenges for the emergence of hybrid projects in the chosen jurisdiction?

1.3.3 Data collection

To identify best practices in the selected jurisdictions, data was collected through two main sources:

- **Relevant literature:** Policy briefs, legislative texts, reports and analyses from reliable sources which could answer the research questions
- **Interviews**: A series of interviews with relevant stakeholders from the selected jurisdictions were held and documented through minutes approved by the interviewees. Interviews were semi-structured, as interviewees were provided the questions in advance to guide the converstation, but then were encouraged to expand on their answers. The identified relevant stakeholders were TSOs (in the case of the UK, the Electricity System Operator – ESO), National Regulatory Auhtorities (NRAs) from the selected jursidction as well as one ORE developer with interest in hybrid projects. (see Table *5*):

Table 5: Identified stakeholders for interviews on best practices in selected jurisdictions.

Jurisdiction	Role	Entity	Interview date
Denmark	TSO	Energinet	23/02/2023
	NRA	Danish Utility Regulator (DUR)	03/03/2023
Netherlands	TSO	TenneT	10/03/2023
	NRA	Authority for Consumers and Markets (ACM)	01/03/2023
UK	ESO	National Grid ESO	07/03/2023
	NRA	Office of Gas and Electricity Markets (Ofgem)	06/03/2023
Multiple	Developer	Ørsted	28/02/2023

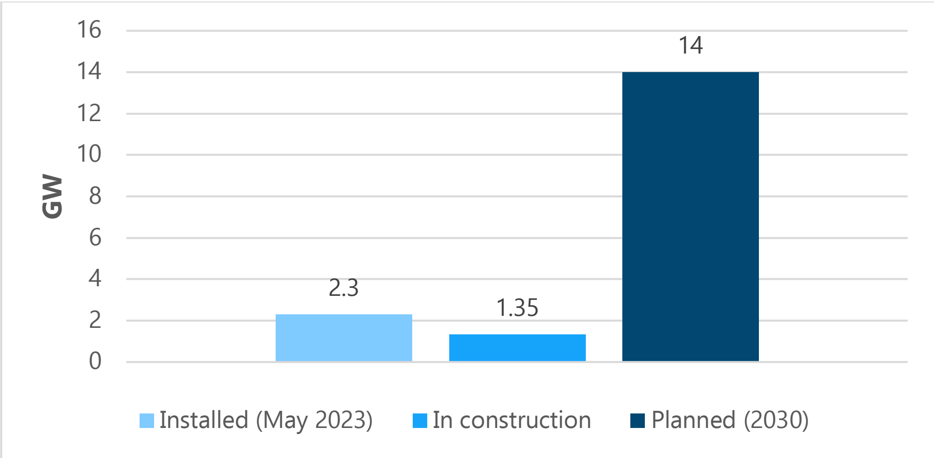
1.3.4 Results of the best practices analyses

In the following, country profiles outlining the best practices for hybrid projects in each jurisdiction are presented.

Denmark

Denmark is a leading country in ORE development, as it hosted the world's first offshore wind farm (the now decommissioned Vindeby) and is home to the first ever, only operating hybrid interconnector (the KFCGS) between Germany and Denmark.[24] Denmark currently has an established offshore wind capacity of 2,3 GW and 1,35 GW are under construction. With the most recent parliamentary agreement on the matter in place (30 May 2023), total capacity may reach 14 GW or more by 2030, as overplanting is allowed.[25] It is a requirement of the agreement that at least 9 GW must be established before the end of 2030.

Figure 32: Offshore wind capacity in Denmark



Source: Danish Ministry of Energy Climate and Utilities (2023)

Criterion 1 - Offshore and onshore transmission planning framework

Formally, there exist two ways to initiate an ORE generation project in Denmark: i) public tendering of projects of a given capacity in state-determined maritime areas, or ii) an "open door" procedure in developer-selected sites for which the developer applies.

Following the approval of a new maritime plan in June 2023, the second of these procedures has been put on hold by Danish authorities and is not expected to continue in the future.[26] In practice, three of the six projects that were paused may obtain approval under a revised open door procedure for which a transition has been initiated (Danish Energy Agency, 2023).

This means that looking forward the main procedure to initiate ORE projects in Denmark is the public tendering process, for which public financial resources are allocated. Denmark has planned to establish two energy islands which involve hybrid projects: Energy Island Bornholm (3 GW) and Energy Island North Sea (3-4 GW with a long-term expansion potential of 10 GW). Of these two, the generation component of Energy Island Borhnolm will be part of the bidding rounds approved by the parliamentary agreement of 30 May 2023, which contemplates granting state aid. In contrast, the entire business model for Energy Island North Sea is undergoing an overarching re-assessment to ensure profitability which was established as a political priority through the parliamentary agreement on the matter (Danish Ministry of Energy Climate and Utilities, 2023b).

[24] In relation to Vindeby, see the press release by Ørsted (2017).

[25] Overplanting refers to the situation in which installed ORE generation capacity exceeds transmission capacity to shore. As part of the recently approved bidding rounds, ORE producers will be allowed to overplant.

[26] On 7 June 2023, all parties in the Danish parliament agreed on a new maritime plan which allocates 30% of all maritime areas to ORE development (Ministry of Industry Business and Financial Affairs, 2023).

Historically, the Kreger's Flak OWF as well as its hybrid interconnector component (the KFCGS) were planned jointly, including its financial model. In parallel to the state aid mechanism approved for the Kriegers Flak OWF, which was part of the parliamentary agreement of 22 March 2012, Energinet as Denmark's designated TSO

initiated a planning process of both the connection to shore as well as the interconnector component of the project (the KFCGS).

Considering the evidence gathered, a few identified practices can be summarized:

- Parliamentary agreements earmark resources (e.g., state aid), bidding conditions as well as specific requirements for the economic model of ORE and hybrid projects, which are then publicly tendered on a competitive basis. More generally, these parliamentary agreements define Denmark's energy policy stance, as they reflect the prioritization of energy policy goals, such as sustainability, affordability and security of supply. For example, the prioritization of profitability in the development of energy islands was established in the corresponding parliamentary agreement (22 June 2020).
- Energinet, in its role as Denmark's designated TSO has the legal mandate to plan and build transmission infrastructure assets and to coordinate with other state bodies (such as the Danish Energy Agency) and international counterparts (partner countries' TSOs) on the specific conditions of the transmission infrastructure.
- Denmark's preferred concept for hybrid projects is energy islands, which comprise: i) transmission assets (connection to shore and interconnection), ii) ORE generation, energy storage and energy consumption (through electrolysers) to develop Power-to-X and iii) the island itself.

In practice, the conceptual development of ORE and hybrid projects is the result of an ongoing interaction between energy policymakers and the technical input from both the Danish Energy Agency and Energinet.

Criterion 2 – International coordination

In Denmark, international coordination is initiated at the highest political level and is then implemented by technical counterparts. In relation with hybrid interconnectors, Denmark has established Memoranda of Understanding (MoU) with Germany and Holland as well as a Memorandum of Agreement with Belgium.

At the technical level, Energinet has entered into agreements with German TSO 50hertz and with the Belgian TSO Elia.

Summarizing:

- Besides multilateral cooperation efforts in which Denmark participates, such as the North Seas Energy Cooperation (NSEC), Denmark engages in bilateral cooperation with relevant stakeholders in connection with the development of hybrid interconnections.

Criterion 3 – Financing of transmission assets

As is the case for all EU Member States, the main cost recovery mechanism for transmission investments is through a combination of tariffs and congestion rent, in the case of cross-zonal interconnections.

In the Danish regulatory framework for Energinet, there must be a clear accounting distinction among its network-related costs and its system-related costs. The first category includes the allowed rate of return, depreciation, and network losses while the second includes the procurement of ancillary services as well as other expenses to operate the system, which cannot be traced directly to the individual network user.

As hybrid interconnection projects fall within the first category, a combination of congestion income, producer-paid tariffs and tariff charges on consumers are expected to cover investment expenses for hybrid interconnectors.[27]

A recent change of relevance for the financing of hybrid projects in Denmark is the change in Energinet's regulatory regime from cost-plus regulation to income-cap regulation. The change (implemented since January 2023) entails a higher risk exposure for Energinet, which would become liable for eventual budget overruns. In contrast, under the cost-plus framework, expenses can be transferred to consumers.

As part of the underlying parliamentary agreements for the development of energy islands in Denmark, it was agreed that net expenses (hybrid interconnector investment and operational costs minus congestion income) should be – to the largest possible extent – be paid by ORE developers.

Identified practices are:

- Denmark expects to recover hybrid interconnector development and operational expenses through a combination of producer-paid, consumer-paid tariffs and congestion income.
- The Danish TSO Energinet is exposed to increased economic risk as a consequence of the implementation of a new regulatory model, which susbtitutes the cost-plus regulatory model with income-cap regulation.
- The underlying political agreement for the development of energy islands in Denmark establishes that transmission infrastructure development associated with hybrid projects should be – to the largest possible extent – cost-neutral for consumers. In practice, this means that ORE developers should cover the costs caused in relation to their connection to the energy islands.

Criterion 4 – Operation and remuneration

Denmark currently operates under two bidding zones: Denmark West (DK1) and Denmark East (DK2). Based on the evidence gathered, there does not exist an ongoing revision of the current configuration of the electricity market, but this is expected to change in the future when hybrid projects become operational.

Another important element of the operation and remuneration framework is the specific agreement on the cross-border cost allocation agreements. In this respect, Energinet and 50hertz have recently agreed on an equal split of costs and benefits in the Energy Island Bornholm hybrid interconnector. The agreement is the result of ongoing cooperation established at the technical and political level.

In summary:

- OBZs are expected to be the market design under which the planned Danish energy islands will operate. However, there does not yet exist a firm decision or ongoing case on the matter.
- Detailed agreements on the cost split of hybrid interconnectors are developed on the basis of bilateral technical and political dialogue.

Criterion 5 – Government policy towards hybrid projects

Gathered evidence indicates that there does not exist one dedicated policy document or legislative framework governing the policy framework for hybrid projects in Denmark. Instead, the overall Danish governance process for energy policymaking is applied.

This – as described before – entails a governance process in which parliamentary agreements define, among many other relevant details, the energy policy stance. Concerning hybrid project in Denmark, a profitability criterion has been one of the pre-conditions for these to become a reality.

[27] The specific suggested design of the cost recovery mechanism for hybrid projects in Denmark is discussed in greater detail in Chapter 3 of the present report.

In other words:

- Specific methods and approaches to develop hybrid interconnections are under ongoing adaptation, development and consideration by participating stakeholders at the technical and political level.
- The Danish government expects the projects to be profitable and to bring about societal benefits. However, the Danish government has had to reconsider this approach, as it has decided to subsidize Energy Island Bornholm and to reconsider the entire business model Energy Island North Sea.Criterion 6 – Perception towards EU policy and regulation
- Criterion 6 – Perception towards EU policy and regulation

The EU regulatory framework for the energy sector is perceived as enabling rather than limiting:

- Stakeholders perceive that there exists a well-developed design for the internal market for electricity which may nonetheless require specific reviews and adjustments.

Criterion 7 – Perceived challenges

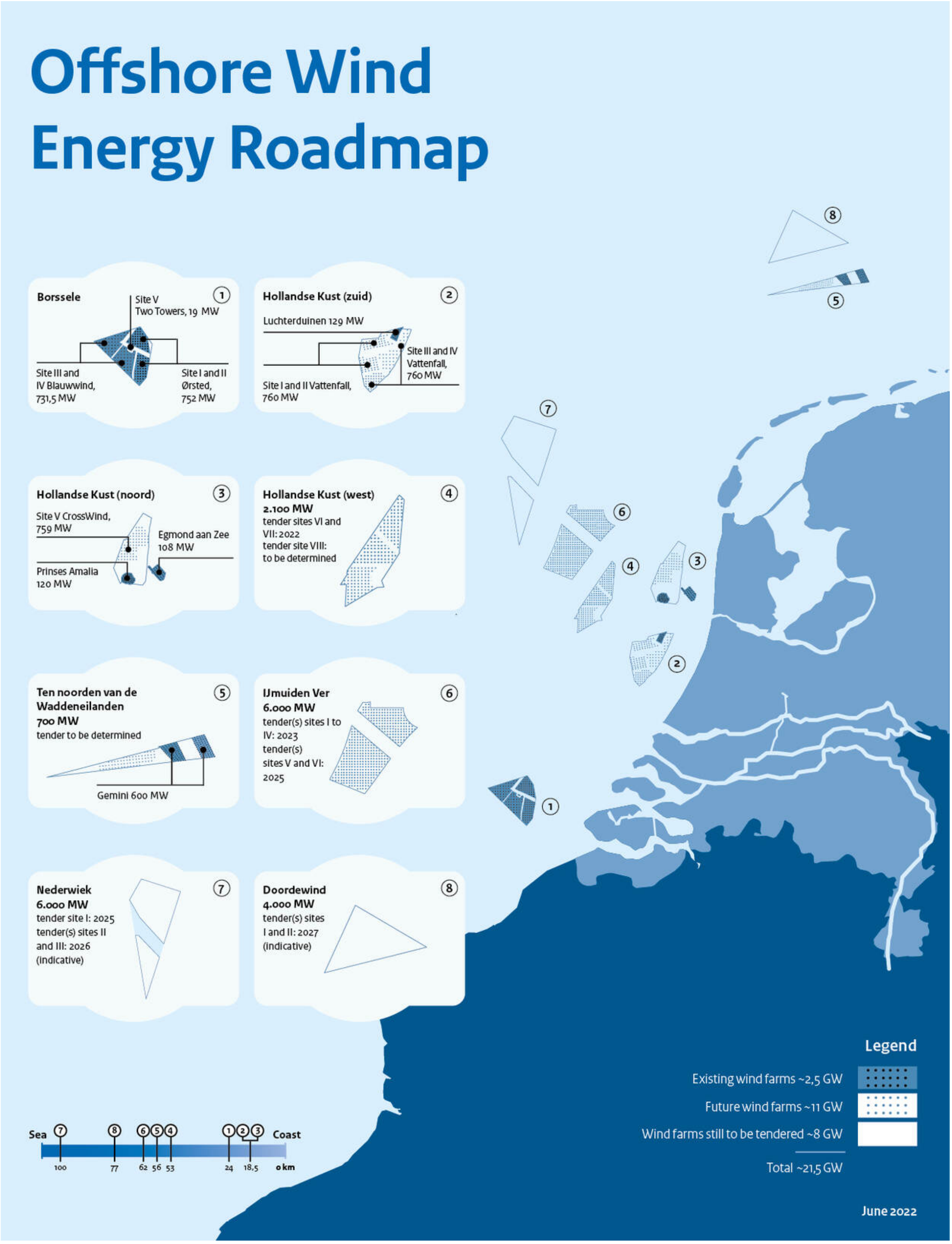
Looking forward, one of the main challenges is the absence of proof of concept of how hybrid projects will fold out in practice. However, the main challenge is for ORE developers which require a solution to the increased risk they will face under an OBZ relative to the HM design. In this respect:

- Re-thinking state-aid mechanisms and risk mitigation instruments will be of relevance for the future consolidation of the OBZ market design. Similarly, measures taken at the EU level such as the increase of the 70% rule to 80% or 90% may give greater certainty to ORE producers.

Netherlands

The Netherlands is another leading offshore wind jurisdiction which (as of June 2022) has a total offshore wind installed capacity of 2,5 GW. Additional sites with a further capacity of 11 GW are under tendering and an additional 8 GW will be tendered with an intended operational start by 2030. Overall, the government of the Netherlands has an ambition of deploying 21,5 GW offshore wind around 2030 (see Figure 33).

Figure 33: Offshore Wind Energy Roadmap of the Netherlands



Source: Government of the Netherlands (2022)

Criterion 1 - Offshore and onshore transmission planning framework

Since 2017, Netherlands has a state-led approach to planning ORE development through which government selects sites and opens for tendering processes in which interested developers may participate. Previous to 2017, wind developers were responsible for site selection and investigation, but this approach was reformed as it

proved ineffective - out of 80 initial applications, only four projects (amounting to less than 1 GW) were built by 2017 (Netherlands Enterprise Agency, 2023a).

The Dutch government, as the main responsible for energy policy development, has set in motion three offshore wind roadmaps which have defined the ambition level and introduced the required regulatory and institutional reforms to support the established goals, including the introduction of a state-led approach to ORE planning.

From a policy perspective, Netherlands has announced three acceleration phases for offshore wind development:

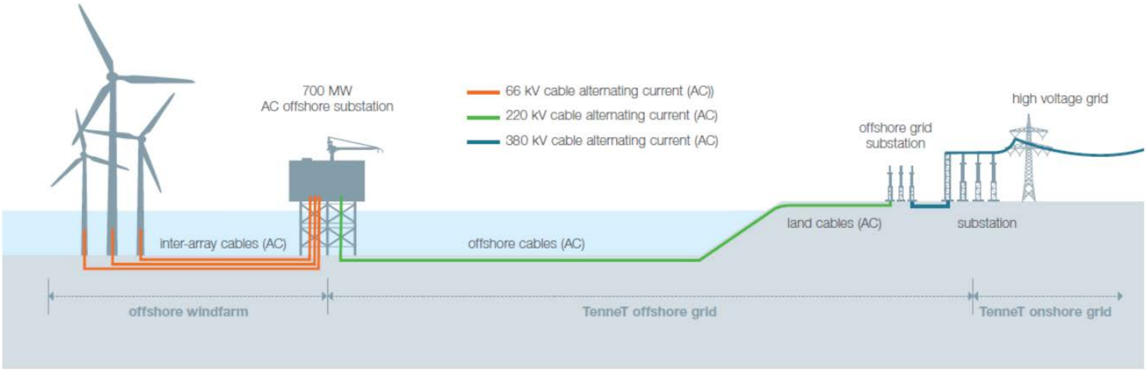
- The first acceleration phase (4,5 GW by 2023) - **Roadmap 2023** was the result of a political agreement (the Energy Agreement for Sustainable Growth) between government and a broad representation of society (employers, trade unions, environmental organizations).
- The second acceleration phase (11,5 GW by 2030) – **Roadmap 2030** appeared under the framework of a National Climate Agreement and the Climate Act. With this, three additional zones were added for ORE development.
- The third acceleration phase (21 GW around 2030) – **Roadmap 2030+** was the result of increased climate ambition expressed by the current Dutch government, which took office in January 2022, in line with the EU's target of reducing CO_2 emissions by 55% by 2030.

From an implementation perspective, once wind farm areas are designated at the maritime planning phase and the roadmaps are announced, site investigations – which include an environmental impact assessment and analyses of local soil, wind and water conditions – are conducted at the expense of the Dutch government. Regarding the transmission infrastructure, the establishment of a grid connection is initiated as early as possible, as the entire planning and development could take between 8 and 10 years.

As the offshore and onshore grid system operator, TenneT has exclusivity in the connection of windfarms. To this end, TenneT has implemented a standardized approach to grid connection which aims at bringing about cost savings:

- For OWFs located at a short distance to shore, **a standard 700 MW** Alternating Current (AC) connection to shore is utilized (see Figure *34*). This is the approach taken in the Borselle site (24 kms from shore), the Hollandse Kust (18,5 kms) and the North of the Frisian site (56 kms from shore)

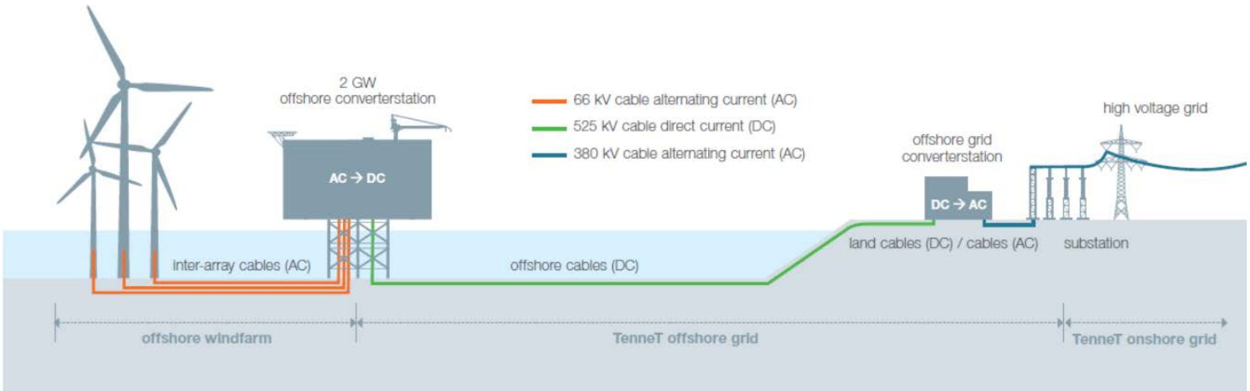
Figure 34: Standard (700 MW) AC connection to shore



Source: Netherlands Enterprise Agency (2022)

- For OWFs located at larger distance to shore, **a standard 2 GW** of Direct Current (DC) connection is employed. For example, this is the approach taken at the IJmuiden Ver site (62 kms from shore and a planned capacity of 6 GW)

Figure 35: Standard (2 GW) DC connection to shore



Source: Netherlands Enterprise Agency (2022)

In addition to the roadmaps which define political ambitions, the government has implemented a **Development Framework for Offshore Wind Energy** to outline the principles for the design, construction, availability, and service life of the offshore grid. The Development Framework, which is periodically updated, stipulates the tasks of TenneT as offshore transmission system operator, provides the sequence for the development of the sites and sets the timetable for commissioning the connection for the sites.

It is on the basis of this framework that TenneT defines 2-year investment plans which are submitted for approval by the Dutch NRA, the Authority for Consumer & Markets (ACM).[28] Before the construction phase of the offshore wind farms, TenneT and the ORE developer sign a Realisation Agreement and a Connection and Transmission Agreement stipulating terms and conditions, including clauses on an eventual delay caused by TenneT.

With respect to hybrid interconnections, the Development Framework recognizes the benefits of this kind of projects, including increased security of supply and postulates the need for **anticipatory investments**:

- Space will be reserved on the (standardised) 2 GW DC platforms for the connection of an interconnector and this space reservation will be part of the standardized connection approach
- The high-voltage installation will also have to be made suitable for future expansion with a hybrid connection

[28] The legal basis for the Development Framework is Section 16e of the Dutch Electricity Act of 1998

Summarizing, identified best practices with regards to the transmission planning framework in the Netherlands are:

- The government sets targets for ORE development based on pre-existing maritime plans
- As the designated offshore and onshore TSO, TenneT is responsible for grid connection and to this end TenneT has implemented a standardized connection approach
- A Development Framework for Offshore Wind Energy is prepared and published by the government in order to provide clarity to stakeholders with respect to the development of the offshore grid. The Framework is periodically updated to reflect the most recent developments.
- The Development Framework has proposed a geographically distributed connection pattern with onshore landing points with proximity to industrial clusters, such that network reinforcements are avoided as far as possible.
- With regards to hybrid projects, the Development Framework stipulates that anticipatory investments, in the form of space reservation in all future 2 GW DC platforms will become part of TenneT's standard connection approach. However, an investment decision on the establishment of an interconnector ("hybridization") is taken separately.
- Based on the analysis conducted by Pöyry (2019), the Development Framework indicates that anticipatory investments in the IJmuiden Ver (6 GW) site are justified as the expected social benefits of a hybrid interconnection with the UK are positive.

Criterion 2 – International coordination

Based on the evidence gathered, Netherlands has established bilateral cooperation with both Denmark and the UK to develop offshore energy infrastructure. With Denmark, there is a signed MoU at the ministerial level and with the UK, an ongoing dialogue between NRAs was confirmed.

Summarizing, identified practices with respect to international coordination include:

- Voluntary participation in multi-lateral fora such as the NSEC and binding engagement with ENTSO-E in the development of Offshore Network Development Plans.
- Bilateral engagement with countries with which there are specific initiatives to develop both hybrid and point-to-point interconnectors, such as the Lion Link project between UK and the Netherlands. The engagement is established between technical stakeholders (between involved infrastructure developers) but also between governments and public authorities.

Criterion 3 – Financing of transmission assets

The Netherlands, as many other EU Member States, follow the regulated investment model through which transmission asset investments are approved by a NRA or oversight authority and then executed by a regulated TSO, which in the Dutch case is TenneT.

The Dutch NRA (ACM) regulates TenneT though an income cap approach through which investments are passed on to the costs that can be recovered through regulated tariff income, which is charged on network users. The depreciation period for offshore grid assets is determined in the 5-year regulation periods. In the latest regulation period, the depreciation period was extended from 20 to 30 years to account for grid investments in sites where final permits still remain to be granted.

In summary, identified practices are:

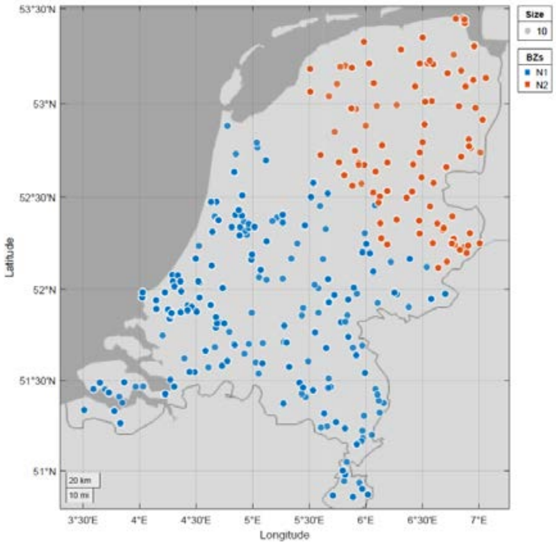
- TenneT, in its capacity as offshore TSO, invests in the offshore grid and recovers its costs through regulated tariff income which is approved by ACM in 5-year regulation periods under an income cap approach.

Criterion 4 – Operation and remuneration

The Netherlands currently operates under a single bidding zone, but this configuration is likely to change. Prior to the decision on alternative bidding configurations issued by ACER in August 2022, in which the Netherlands is split into two bidding zones (Figure *36*), TenneT had suggested instead splitting into three bidding zones.

TenneT had made its recommendation based on the observation of large electricity flows from north to south which are nonetheless met with internal congestion, which is nonetheless met with congestions within the existing bidding zone. Although TenneT has expressed commitment to reinforcing its internal network, it does not consider it sufficient to ensure compliance with the 70% rule.

Figure 36: Alternative bidding zone configuration decided by ACER



Source: ACER (2022)

Regarding hybrid projects, evidence indicates that future hybrid projects are expected to operate under an OBZ design. Although the potential forthcoming reconfiguration of bidding zones does not directly affect the establishment of OBZs, distributional impacts may be expected depending on the zone to which existing OWFs will belong. Any forthcoming bidding zone reconfigurations will also affect the future flows and prices, which will impact the emerging flows after OBZs are eventually established.

Summarizing, identified practices are:

- OBZs are expected to be the market design under which hybrid projects will operate
- Before OBZs are established in connection with the establishment of hybrid interconnections, the Netherlands will likely undergo a bidding zone reconfiguration which will impact the flows and price formation process. This reconfiguration is the result of identified onshore network constraints within the existing (single) Dutch bidding zone.

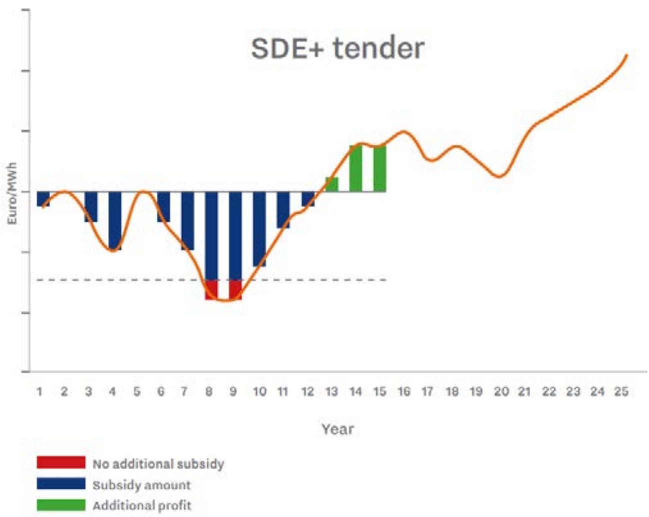
Criterion 5 – Government policy towards hybrid projects

Although the Netherlands does not have one dedicated or specific policy document for hybrid projects, specific guidelines are being incorporated into the overall policymaking process for ORE development, as can be observed in the Development Framework.

One area of innovation in governmental policy towards ORE development in the Netherlands is in the design of tenders and subsidy schemes for future ORE development. There are three main models applied (Netherlands Enterprise Agency, 2023a):

- **Model 1 – Tender for the lowest bid**: ORE developers compete to obtain state aid in the form of a Feed-in premium in which generators obtain support in case prices fall below an auction price (solid line in Figure *37*), but receive no additional subsidy if prices fall below a base electricity price (dotted line in Figure *37*).

Figure 37: Feed-in premium in the Netherlands



Source: Netherlands Enterprise Agency (2023a)

- **Model 2a – Subsidy free tender (feasibility assessment):** Instead of granting state aid, ORE generators operate without state aid and obtain the right to develop the OWF on the basis of a feasibility assessment, which is evaluated by an independent and confidential team of experts. The considered award criteria are non-financial and include aspects such as the contribution to the national energy mix, aquaculture, fisheries among others. During 2022, site VI in the Hollandse Kust West was awarded on the basis of ecological innovation while Site VII was awarded on the basis of system integration.
- **Model 2b – Subsidy free tender (feasibility assessment + financial bid):** If there is competition among ORE developers to obtain a permit for the same location, the feasibility assessment can be complemented with a financial bid. In practice, this was applied to the Hollandse Kust West Site VI and VII, where the maximum bid was capped at 50 million EUR, with relatively lower points awarded for financially lower bids.
- **Model 3 - Tender for highest auction price**: Obtaining revenue from the allocation of a right to develop an OWF is also legally acceptable in the Netherlands. Earned revenue by the state can be used to cover the costs of developing grid infrastructure as well as other expenses related to site investigations and the environmental assessment.

In summary, identified practices are:

- Hybrid projects are progressively being incorporated to the practice of policymaking in the Netherlands, although a dedicated policy statement on the matter does not exist.
- Looking forward, the main policy approach to ORE development in The Netherlands is the subsidy free model.

Criterion 6 – Perception towards EU policy and regulation

Evidence gathered indicates that while the EU policy and regulatory framework on the internal market for electricity is considered as an enabling rather than a hindering element, the specific details on the establishment of OBZs must be considered at the EU level. Similarly, further guidance on the design and application of state aid mechanisms will also be vital for hybrid projects.

In summary:

- Top-down regulation at the EU level may be called for in relation to the establishment and introduction of OBZs and with respect to the design and application of state aid mechanisms.

Criterion 7 – Perceived challenges

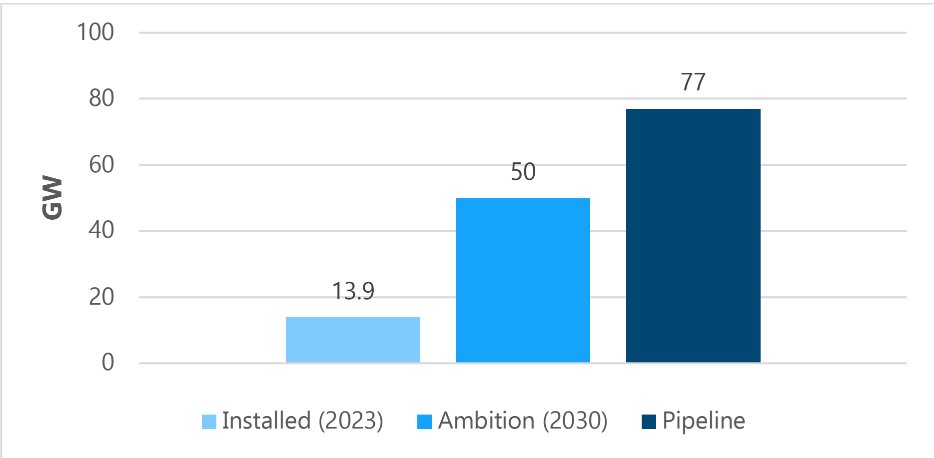
Based on the gathered evidence, there were two main challenges identified:

- The issue of cross-border cost allocation mechanisms between EU and non-EU jurisdictions (e.g., the UK) may become particularly contentious, as EU regulation applies only on one side of a hybrid interconnector such as the LionLink. This raises questions with regards to the application of both the 70% rule and on the regulatory framework on the usage of congestion rents. Incentive alignment can become more complicated in such cases.
- Also with respect to the ongoing discussions on LionLink, the hybrid interconnector between Netherlands and the UK, an important consideration must be given to the post-Brexit trading arrangements between the EU and UK. After the UK left the EU, the Single Day-Ahead Coupling (SDAC) through which transmission capacity was auctioned implicitly ceased to operate, meaning that traders must rely on an explicit auction of cross-border transmission capacity before trading with electricity in the day-ahead time frame. Following the Trade and Cooperation Agreements, a possible solution on the matter may be the application of multi-region loose volume coupling which unlike SDAC determines cross-border flows, with prices determined in a subsequent step. [29]

United Kingdom

Currently, the UK's offshore installed capacity is of 13,9 GW and has an ambition of reaching 50 GW by 2030. British government policy has also established a goal of reaching at least 18 GW interconnector capacity by 2030, with a currently operational interconnector capacity of 8,4 GW. Against this backdrop, MPI development can be observed as a mutually reinforcing goal for both interconnector development in general and offshore wind development in the UK.

Figure 38: Offshore wind capacity in the UK



Source: Department for Business & Trade (2023)

[29] Source: https://www.nemo-committee.eu/assets/files/information-note-about-the-exiting-gb-parties-in-sdac.pdf. Regarding the intraday time frame, there is implicit auctioning of capacity between GB and the I-SEM.

Criterion 1 - Offshore and onshore transmission planning framework

ORE development in the UK operates under a developer-led model. Following leasing rounds for seabed areas organized by The Crown Estate, successful ORE developers obtain the right to investigate sites and advance

their projects to the following stages of project development, which include: i) the development and consenting stage, ii) participation in Contract for Difference (CfD) support auctions, iii) construction and iv) operation. Overall, the entire process may take approximately 10 years to complete.

Under this planning model, the developer builds its own connection to shore and after a competitive process ran by the GB market regulator (Ofgem) takes place, transmission assets are divested from the OWF developer to an Offshore Transmission System Operator (OFTO) which obtains an offshore transmission licence. In its capacity as Electricity System Operator, National Grid ESO (NG-ESO) identifies the best onshore connection points for ORE. Overall, NG-ESO is responsible for planning and – in cooperation with government – is currently advancing a Holistic Network Design framework, which entails transitioning from an uncoordinated approach between offshore wind connections and onshore grid reinforcements to a more centralized and strategic approach.

In what concerns hybrid (MPI) project development, Ofgem initiated in 2022 a pilot project to attract the interest of project developers to develop such projects between a partner country and the UK. Ofgem received four project applications and in December 2022 decided to move forward with two of these: one to Belgium and another one to the Netherlands.[30] Later (in June 2023), Ofgem launched a consultation on the enduring regulatory and market design regime for MPIs in the UK. This entails a broader revision of the UK's licensing framework, the financing mechanism for the transmission assets, the market environment in which ORE will operate and the support mechanism that will be granted.

Summarizing, a few practices can be identified:

- Upon expression of interest from developers, MPI projects are initiated in the GB as a parallel and independent process to the bidding of offshore wind generation, meaning that although interconnection projects are conceived as hybrid from the start, the specific details of the ORE generation project to be connected to the interconnector are unknown.

- Projects that passed the eligibility check but do not progress as MPIs may be later re-considered as point-to-point interconnectors, meaning that the existing framework is both flexible and pragmatic. Voluntary coordination with offshore wind development is desired, but if this is not achieved, the framework gives the option to default to a standard point-to-point interconnector.

- In Ofgem's view, a simple modification of the OFTO licensing model did not prove sufficient to accommodate the new licensable activities to be developed, which is why Ofgem suggests expanding the licensing framework to a broader category of assets, namely Offshore Hybrid Assets (OHAs). Within this category, there are two main categories and the defining characteristic for these is the location of the ORE generation facility:

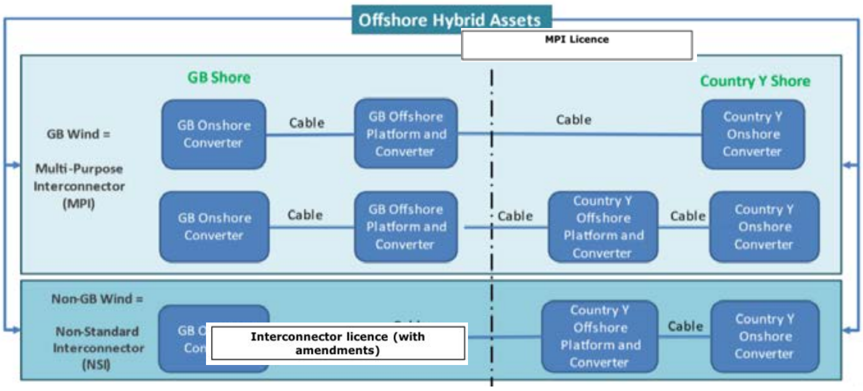
    - **Non-Standard Interconnectors (NSIs)** interconnect an ORE facility located outside the GB market with an onshore connection point in GB. However, outside GB, the cable serves the dual purpose of evacuating ORE generation and interconnecting markets.

    - **Multi-purpose interconnectors (MPIs)** also serve the dual purpose of evacuating ORE and interconnecting. However, both activities are located in the GB market. Thus, an MPI connects an ORE generation facility in the GB market to either an onshore landing point or to another

[30] Two of the projects were from Norway, one to Belgium and one to the Netherlands - in total, 6 GW interconnector capacity. The projects to Belgium (Nautilus) and to the Netherlands (LionLink) were granted interconnector Licenses by Ofgem on 14 July 2023.

ORE generation facility – but in both cases, these must be located outside the outside the GB market.

Figure 39: Visual representation of OHAs



Source: Ofgem (2023)

Criterion 2 – International coordination

Gathered evidence indicates that coordination between the UK and partners countries for hybrid projects has taken place at the ministerial level, between regulatory authorities and between technical counterparties.

However, after Brexit, the previously existing channels of cooperation at the EU level have weakened substantially. For example, NG-ESO left ENTSO-E which means that NG-ESO will not participate in the preparation of Offshore Network Development Plans, which are part of the TEN-E Regulation. Similarly, although it follows from the TCA between EU and UK that the implicit capacity allocation of capacities through Multi-Region Volume Coupling is the way forward, the mechanism still is not in place. On the other hand, the UK voluntarily re-joined NSEC, which is a positive sign.

In summary:

- Despite Brexit, cooperation between UK and its governmental and technical counterparties has continued.

Criterion 3 – Financing of transmission assets

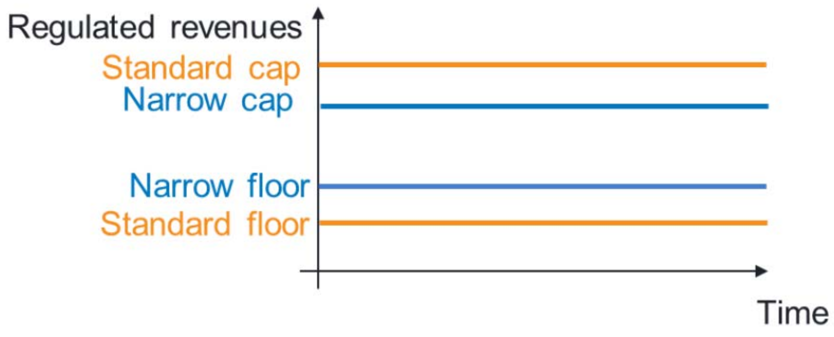
The cap and floor regime, introduced by Ofgem in 2014, meant the establishment of a regulated route for interconnector investment between the GB market and partner countries. Prior to this, most interconnectors were built on a merchant basis, which entailed greater risk exposure and with this the possibility of higher rewards for the investors.

In contrast to the rest of Europe, the UK does not currently have a fully regulated model, which means that the most suitable candidate model for financing OHAs is the cap and floor regime. However, given the capital intensive nature of hybrid projects, Ofgem has recommended a revised, compartmentalized mechanism in which:

- The offshore converter platform is to be funded by a Regulated Asset Base (RAB) with fixed return over a pre-specified lifetime. This is in order to minimize the risk exposure of the most capital-intensive part of the business.

- The cable is to be funded by a “narrow” cap and floor in which – relative to its point-to-point counterparts – the minimum level of revenue is increased, and the maximum level of revenue is decreased. This allows the investor securing a *higher* level of income while returning payments to consumers after a *lower* level of maximum revenue is realized.

Figure 40: Narrow Cap and Floor



Source: Ofgem (2023)

Criterion 4 – Operation and remuneration

The GB energy system is undergoing a complete revision of its market design arrangements, through the ongoing Revision of Electricity Market Arrangements (REMA) where fundamental issues such as nodal pricing and centralized dispatch are being reconsidered. While REMA concerns the onshore market, the enacted reforms following from it will eventually have an impact on the flows and price that will ultimately be earned by ORE producers. This may have significant impact on the ORE developers' business case.

The most relevant question is whether ORE producers will operate under an OBZ market design. In this respect, Ofgem:

- Has recommended the introduction of OBZs as part of the introduction of OHAs.

Criterion 5 – Government policy towards hybrid projects

The existing licensing framework for interconnectors operating in GB requires amendments to the licensing regime which will be enacted in the Energy Bill upon recommendation from the government. However, the final text of the Energy Bill, including the clauses related to OHAs, may be amended.

Another relevant aspect is that the UK government expects to continue providing state aid to ORE generation, including producers connected to an OBZ in a hybrid project.

In summary:

- Ofgem recommend a change in the existing licensable activities and a modification of the CfD to reflect prices in an OBZ

Criterion 6 – Perception towards EU policy and regulation

As a now outsider to the EU policy and regulatory framework, the main issue to address is the clarity in the relationship between UK and EU. Although the TCA between UK and EU has pledged to establish transparent mechanisms, many of these still are not in place.

Criterion 7 – Perceived challenges

There were two main challenges identified: cross-border cost allocation and the absence of a SDAC.

1.3.5 Comparison of best practices

To summarize the findings on best practices, Table *6* compares the most relevant criteria:

Table 6: Comparison of best practices

Criterion	*GB*	*Netherlands*	*Denmark*
Planning	**Developer-led model:** developers interact with Ofgem to apply for the establishment of multi-purpose interconnectors (MPIs). Specific projects express interest and initiate a cap and floor regime application; may end as point-to-point interconnectors if no offshore wind generation connects.	**Plan-led model:** government publishes and updates the Development Framework for Offshore Wind Energy; TenneT is assigned the role of offshore grid operator. Standardized grid connection approach (2 GW DC platforms); Anticipatory investments: space is reserved, high voltage facility is hybrid ready.	**Plan-led model:** parliamentary agreements earmark resources for specific offshore wind projects; Energinet has mandate to build transmission assets. Focus on energy islands, which comprise: i) transmission, ii) generation (possibly storage and demand for PtX), iii) the island itself
Development and ownership of transmission assets	**OFTO model:** developer builds transmission assets and then divests to an offshore transmission operator in competitive process	**TSO model:** TenneT builds and owns transmission assets	**TSO model:** Energinet builds and owns transmission assets
Financing of transmission assets	**Cap and Floor:** partly regulated model, however not the enduring financing model	**Fully regulated:** financed by TenneT, recovered through income cap, supplemented by congestion rents earned.	**Fully regulated:** financed by Energinet, net expenses recovered through income cap. Most of net expenses to be transferred to the offshore wind developer.
Remuneration of generation and hybrid transmission	**Assumption:** future hybrid interconnections will be connected to offshore bidding zones (OBZs)	**Assumption:** future hybrid interconnections will be connected to offshore bidding zones (OBZs)	**Assumption:** hybrid interconnections will be connected to offshore bidding zones (OBZs)

1.4 Concluding remarks on pros & cons and best practices

In this chapter, three main themes have been discussed:

- **The existing EU regulatory and market design principles for the operation of ORE and hybrid projects**. The analysis indicates that the introduction of OBZs as well as the risk mitigation mechanisms are two of the most important elements to consider in the future development of hybrid projects. Although there is consensus on the benefits of this approach, there still is insufficient clarity as to how the process will unfold in practice.
- **The energy modelling evidence**, which has been gathered throughout years of techno-economic analyses reveals that hybrid projects are capable of bringing about net socio-economic benefits resulting from CAPEX and OPEX savings as well as increased utilization of the existing infrastructure.

Although the additional benefits are not always significantly higher, these tend to increase in the long run.

- **The best practices for hybrid project development in three selected jurisdictions. A few observations are in line:**
  - The analysis indicates that although Denmark and the Netherlands share a plan-led approach, these have significant differences in their approaches. For example, regarding anticipatory investments the Netherlands is open for this approach, which opens up for the possibility of future hybridization of projects. However, Denmark does not consider this possibility.
  - A point of coincidence between Netherlands and UK is that ORE development is expected to happen under market terms with minimal or no subsidy.
  - In sharp contrast to both Netherlands and Denmark, the UK has a developer-led approach in which investors express their interest for developing hybrid projects. In parallel, ORE developments take place in the expectation that there will be voluntary coordination between ORE and interconnector developers.
  - All jurisdictions coincide that they will introduce OBZs when hybrid projects become operational.

2. RECOMMENDATIONS FOR AN IRISH HYBRID INTERCONNECTION POLICY

2.1 Process underlying the recommendations

Based on the pros & cons and best practices analysis of chapter 1, the most important and most applicable lessons for Ireland were derived. With this information as background, the recommendations presented on this chapter follow from two main inputs:

- **Preliminary working hypotheses:** an expert understanding of the state of the art in hybrid interconnection practices and the existing regulatory framework surrounding it, allowed identifying a set of preliminary working hypotheses for Ireland's hybrid interconnection policy. It was argued that the policy framework should at least contain:
    - **A clear incentive for coordination in the ORE planning process**: a successful regulatory and policy framework would create a mechanism for developers and EirGrid to formally discuss and consider the possibility of planning for hybrid interconnections in the early stages of ORE projects. The approach to planning here should integrate both onshore and offshore transmission as well as generation assets. If both radial and hybrid interconnections are possible configurations, a successful policy would facilitate the choice of a hybrid interconnection, if there is evidence of benefits arising from this choice.
    - **A clear framework for cross-border cooperation, including the UK:** hybrid interconnectors involve two or more countries. The Irish framework could, for example, formalize and require the periodical screening and early planning of hybrid projects with neighbours, such as the UK and France. However, the post-Brexit relationship between Ireland and the UK may need greater attention given their proximity and existence of offshore wind projects.
    - **A clear financial incentive to plan and develop hybrid interconnections,** which may include a de-risking framework and direct incentives to develop this type of infrastructure.
    - **A clear interaction with the existing EU and Irish regulatory framework governing the electricity market.** A successful regulatory framework must observe specific EU regulations, such as the 70% rule, as well as the relevant national Irish legislation such as the Electricity Regulation Act and other relevant Irish Statutory Instruments (e.g., S.I. No. 445/2000).
- **Stakeholder engagement and validation:** the abovementioned working hypotheses together with preliminary versions of the policy recommendations (outlined in a Policy Options paper) were the subject of dialogue with stakeholders such as EirGrid, CRU and DECC which provided specific input and validation on the understanding of the Irish context. Based on input obtained from these stakeholders, recommendations were iterated and subsequently presented to a broader audience which included state agencies and industry representatives (Appendix 2 summarizes the findings from the Workshops with Irish stakeholders).

The process to reach the present final recommendations can be summarized graphically as shown in Figure *41*.

Figure 41: Process underlying the recommendations

2.1.1 Interaction with Ireland's Interconnection Policy Statement of July 2023

In parallel to the development of the policy recommendations presented in this document, DECC initiated in June 2022 a technical consultation to update Ireland's policy statement on electricity interconnection, which dates from 2018 (DECC, 2022). As a result of this process, a new policy statement was adopted in July 2023 and some of the aspects outlined in the updated statement relate to the contents of the present recommendations for a hybrid interconnection policy. In particular, Ireland's Interconnection Policy Statement of July 2023 commits to (DECC, 2023b):

- Investigating the feasibility of hybrids in the context of Ireland's forthcoming offshore grid planning framework, and proceeding with this kind of projects if gathered evidence supports this decision.
- Developing an additional (potentially hybrid) interconnector with Great Britain by 2030 besides Greenlink, which is expected to become operational by 2024.
- Developing a potentially hybrid project with Belgium/Netherlands.
- Laying out an Offshore Transmission Strategy (to be updated every 5 years) which is coherent with the ORE Future Framework and Ireland's Offshore Wind Industrial Strategy.
- Integrating interconnector forward planning with ORE forward planning, terrestrial grid planning and the broader EU forward planning such that this feeds inputs into the Designated Maritime Area Plans (DMAPs) for ORE and relevant regional or local plans.
- Establishing a Memorandum of Understanding with the UK to establish a cooperation framework on renewable and low carbon energy with a special focus on electricity interconnection.
- Exploring the possibility to develop hybrid interconnections to reduce development intensity, facilitate policy development and maximize export opportunities and to further develop a policy framework for multi-purpose (hybrid) interconnectors.

2.2 Why hybrid interconnections in Ireland?

Concerning Ireland's interconnector policy and its ORE development ambitions, engagement with stakeholders revealed that there are three main reasons to develop hybrid projects in Ireland:

- **Cost-effectiveness:** hybrid interconnections have the potential to increase the cost-effectiveness in the utilization of ORE, relative to radial-only connections. For example, hybrids reduce the need for offshore grid investments, with ensuing effects on total system cost and environmental impact.
- **Increase cross-border interconnection**: because hybrid interconnections are one type of interconnections, they are in line with Ireland's ambition to increase Ireland's interconnection to support its renewable ambitions and to improve security of supply through the integration with the EU internal market for electricity.

- **Support Ireland's Climate Action Plan and ORE development:** hybrid interconnectors reinforce and support Ireland's renewable energy target of 80% in total electricity generation, including at least 5 GW offshore wind (3.1 GW allocated in Phase 1).

2.3 Success criteria – what should the hybrid interconnection policy achieve?

Similarly, engagement with stakeholders confirmed five success criteria for a hybrid interconnection policy for Ireland. Ireland's interconnection policy shall:

- **Elucidate the potential net socio-economic benefits of investing in hybrid interconnections**, relative to radially connecting ORE to shore. As the preceding analysis has shown (see chapter 1), hybrid interconnections are one interesting option for energy systems, so long as these bring about net socio-economic benefits. However, this is not always the case, as the specific configuration of the project will determine the cost and benefit. The interconnection policy should elucidate if these benefits exist.
- **Provide clarity for the future development of hybrid interconnections**. The policy should provide clarity to all market participants and to relevant stakeholders in relation to the development of hybrid interconnectors. For example, it is expected that besides EirGrid, private investors may participate in such projects or that some form of joint venture could emerge. The hybrid interconnector policy should therefore provide clarity as to what will the business model for these projects be and what will the access route for market participants be.
- **Create a framework to plan for hybrid interconnections while facilitating the economies of coordination between ORE generation and offshore transmission asset owners**. With its pre-defined ORE phases, the transition to a plan-led regime provides an excellent opportunity for ORE development to reinforce hybrid interconnector development and vice versa. The policy should help identify early opportunities for the emergence of hybrid projects in parallel to the transition to a plan-led regime. In other words: as ORE will have to be connected under any situation, an evaluation of a possible hybrid configuration should also be considered.
- **Incentivize inter-governmental cooperation and operationalize it at the technical level**. The hybrid interconnector policy should clearly assess the roles and procedures for establishing inter-governmental cooperation. For example, the policy statement must establish if the process will be initiated by the office of Ireland's Energy Minister or other top government official and what type of agreements should be sought. The policy should also describe the process to engage technical counterparties in the process and in this respect the participation of EirGrid will be highly relevant.
- **The hybrid interconnection policy must be an integral part of Ireland's (general) interconnection policy and interrelate with the Designated Maritime Area Planning (DMAP) framework**. Because Ireland is now guided through a holistic approach to maritime planning, the hybrid interconnection policy should interact with the DMAPs.

2.4 Key challenges faced by hybrids projects in Ireland

The analysis conducted together with the engagement with stakeholders has identified three key challenges for the emergence of hybrid projects in Ireland:

- **The EU regulatory and market design framework**: both the emergence of OBZs and the risk mitigation measures for ORE developers operating under OBZ remain unregulated at the EU level.
- **The EU-UK relationship:** although the TCA between UK and EU is in place, specific details still remain to be clarified. For instance, the introduction of the multi-region loose volume market coupling mechanism remains to be established.

- **Project complexity:** besides the technical aspects, hybrid projects require considerable effort to align interests.

It is recommended that these three key challenges determine the prioritization of activities in the development of a hybrid policy for Ireland.

While the resolution of these challenges depends to a large extent on ongoing processes and interactions by other stakeholders (e.g., negotiations on EU regulation), it is recommended that Ireland proactively engages in dialogue with relevant stakeholders and initiates specific actions and more detailed analyses on areas that Ireland can control. For example, analyses on the introduction of OBZs, the design of risk mitigation measures for ORE producers and bilateral engagement with the UK and other relevant jurisdictions with which hybrid projects could emerge.

2.5 Recommendations

The recommendations are presented on the basis of the three following definitions:

- **Policy instruments:** The tools or control mechanisms used to dictate or substantiate the policy. Some of these instruments already exist in the Irish and EU energy policy framework while some others are recommended implementations.

- **Recommended policy or regulatory option:** The recommended policy/regulatory stance or policy/regulatory approach to implement. It is important to distinguish here between energy policy, which is established by the Irish government, and regulation, which is controlled by the Commission for Regulation of Utilities (CRU). Some of the recommendations may apply to both areas, but this in no way suggests that the due division of responsibilities between policymaking and regulation should be modified.

- **Opted-out policy options:** The policy options that are opted out, which could be implemented as an alternative to the recommended policy option in case the recommended policy is not implemented. This can be understood as a counterfactual to the recommended policy option.

Recommendations on transmission planning

It follows from the policy statement on the offshore electricity transmission system that EirGrid will develop, operate, and own Ireland's offshore transmission system (DECC, 2021). In this capacity, EirGrid should be responsible for designing the concept of the connection approach of offshore renewable energy (ORE) and for evaluating the economic viability of hybrid interconnections.

Recommended policy instrument: Create an offshore transmission strategy, which includes a holistic design approach for onshore and offshore network development

In line with EU regulation, EirGrid produces national grid Development Plans (NDP) for Ireland, among several other network planning documents (see Figure 42).

Figure 42: EirGrid's planning documents

Source: EirGrid Transmission Development Plan · 2021-2030

However, NDPs currently addresses offshore grid developments only in a broad way, without specific consideration given to the connection of offshore wind farms to the onshore network and the eventual establishment of hybrid interconnections.

To address the increasing offshore grid planning requirements, in line with Ireland's ORE ambitions, it is recommended to develop an **offshore transmission strategy**, which includes a **holistic offshore-onshore design approach**, which is part of Ireland's NDP. The proposed offshore network development plan should at least:

- Include cost/benefit scenarios and analyses of hybrid interconnection viability, including detailed modelling of the electricity market.
- Enable cooperation with relevant countries (UK + North-Sea and Atlantic Basin countries).
- Complement the ONDP prepared in the context of formal cooperation within the EU (ENTSO-E's offshore network development plans).
- Establish the connection approach of planned ORE, including wind farms.
- Determine the required onshore network reinforcements and other onshore network interactions resulting from developing the offshore network.
- Present the results of cost-benefit analyses considering a radial/direct connection to shore vs. a hybrid interconnection.

Recommended policy option: Open for the possibility of performing anticipatory investments to enable hybrid interconnections in specific areas where evidence has shown potential socio-economic benefits of hybrid interconnections

To enable the emergence of hybrid interconnections as a preliminary step in the development of an offshore grid, it is recommended that EirGrid develops (possibly standardized) **anticipatory investments** in the connection of ORE. The main benefit of this approach is to enable a scalable approach rather than investing in bigger and more complex projects from the outset. An important benefit of this approach is clarity, as developers would be able to plan based on a clear commitment. For example, by committing to an anticipatory investment at the ORE connection stage, a transmission asset developer may become interested in establishing an interconnector. However, the main potential disadvantage of this approach is that anticipatory investments commit consumers to underwriting an asset that may not be fully utilized in the future.

Opted-out policy options: case-by-case investments

The alternative to developing anticipatory investments is to evaluate and develop hybrid interconnections as part of projects that have been originally conceived as hybrid, and to invest as planned without deviating from the initial scope of investment. According to this model, investment is lumpier and more discontinuous and may limit the gradual emergence of a meshed grid.

Table 7: Summary of policy recommendations on transmission planning

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Offshore Transmission Strategy, which includes a holistic design approach for onshore and offshore network development. This should include cost/benefit scenarios and analyses of hybrid interconnection viability in cooperation with relevant countries (UK + North-Sea and Atlantic Basin countries) as well as determine the required onshore network reinforcements and other onshore network interactions resulting from developing the offshore network. International ONDP, which is part of the TYNDP prepared by ENTSO-E.	Open the possibility to plan and execute **anticipatory investments**, which allow for future "hybridization", if evidence in favour of hybrid interconnections is clear. These investments may be planned and executed in specific areas where potential has been demonstrated.	**Case-by-case planning of investments**: conduct cost-benefit analyses to determine the viability of hybrid interconnections. **Invest as planned:** making investments to the extent necessary and only if there is a guarantee to go ahead with the project.

Recommendations on international cooperation

The coordination between countries intending to interconnect is of vital importance, both at the political level and at the technical level.

Recommended policy instruments: memoranda of understanding (MoU), letters of intent (LI), hybrid asset network support agreements (HANSAs)

A limited set of instruments to enable cooperation between countries willing to establish mutually beneficial energy infrastructure projects does not exist. Instead, these can be bespoke and may range from general, nonbinding agreements such as MoU, more specific agreements such as LI or project-specific agreements such as HANSAs, which commit the parties to providing legal and regulatory certainty for hybrid projects. The inclusion in the list of the EU's Project of Common Interest (PCI) and Project of Mutual Interest (PMI), which is part of the transmission planning process can also be seen as instruments to promote international cooperation between the countries.

The specific choice of instrument will depend on the case, reflects the level of mutual political understanding and commitment as well as the usual practice in each country.

Recommended policy option: be proactive in the establishment of political and technical cooperation between countries

To enable hybrid interconnections, it is recommended that cooperation at both the political and technical level is prioritized, for example between TSOs. The responsible entity to operationalize this cooperation could be the office of the Minister for the Environment, Climate and Communications of Ireland.

The countries targeted for cooperation must be chosen and prioritized on the basis of objective technical and economic criteria. Besides the UK, which is an obvious choice due to the geographical proximity with Ireland, the EU TEN-E regulation establishes that Ireland belongs to the North Sea offshore grid (where Belgium, Denmark, Germany, Ireland, France, Luxembourg, Netherlands, and Sweden participate) and the Atlantic offshore grid (Spain, France, Portugal) corridors.

Opted-out policy option: be reactive in the establishment of political and technical cooperation between Ireland and interconnecting countries

The opted-out policy option is to be reactive in the establishment of political and technical cooperation. Rather than choosing and prioritizing countries to establish cooperation, Ireland would wait for other countries or parties (for example, developers) to express interest in the development of hybrid interconnections.

Table 8: Summary of policy recommendations on international cooperation

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Memoranda of understanding (MoU), letters of intent (LI), hybrid asset network support agreements (HANSAs)	**Proactively** establish political and technical cooperation between Ireland and relevant countries	Be **reactive** in the establishment of political and technical cooperation between Ireland and interconnected countries

Recommendations on the financing of transmission assets

In an HM design framework, connections of ORE to shore are considered internal transmission assets whose cost is to be recovered through tariffs. In contrast, hybrid interconnections operating under OBZs serve the dual purpose of transporting offshore electricity to markets as well as interconnecting two bidding zones. In this case, both congestion rent, and tariffs are the revenue source to finance the asset – however, specific details depend on the chosen cost recovery model.

Recommended regulatory instruments: fully regulated model, merchant model, partly regulated model (Cap and Floor)

The default financing model for interconnectors in the EU is the fully regulated model, according to which network users finance transmission investments, which becomes part of the allowed revenue to be recovered.[31] In this framework, both network tariffs (charged on consumers and producers) and congestion revenues finance the investment. However, it must be noted that congestion revenues may not always be the main financing source of a specific project, as according to article 19 of the Electricity Regulation, congestion income earned

should primarily be directed to guaranteeing that capacity allocated to the market is actually available or to maintain or increase cross-zonal capacities in general. However, this income can be saved by TSOs or used for tariff reductions. [32]

A polar opposite of the fully regulated model is the merchant model in which congestion rent fully finances the investment. A hybrid model (cap and floor) establishes both a minimum and maximum revenue that the interconnector may earn. Revenues below the floor will lead to compensation (through tariffs) from the regulator (or relevant entity) to the transmission developer, while revenues above the cap will lead to funds been transferred back to consumers.

Given the emerging nature of hybrid interconnections, it is recommended that the three models are considered without committing to one specific financing model. The models can be the starting point of a specific cost recovery mechanism for hybrids which could combine features of the three.

It must also be highlighted that this area pertains to CRU's area of competence which has implemented a Cap and Floor model (e.g., Greenlink) on specific situations, but has also decided a fully regulated model when it has evaluated it as appropriate (e.g., Celtic Interconnector).

Recommended policy option: be open to the partly regulated model (Cap and Floor Regime)

Although the default financing model is the fully regulated one, it is recommended that there is openness to the cap and floor model, as it avoids committing to fully underwriting investments on behalf of Irish consumers. One advantage of this model is that it provides a framework that can provide private investors with regulatory certainty while providing incentives for innovation and efficient operation through the exposure to market-based revenues.

Opted-out policy options: consider exclusively either the fully regulated or merchant model

Although it is suggested that the primary choice is the cap and floor model, specific hybrid projects may be considered exclusively as either fully merchant or fully regulated, depending on the specific situation.

Table 9: Summary of policy recommendations on the financing of transmission assets

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
Regulated model, partly regulated model (cap and floor), merchant model (compatibility with neighbouring country must be accounted for).	Be **open to cap and floor** regime for Ireland's part of a hybrid interconnector project.	Consider ***only*** either fully regulated or merchant model depending on the situation.

[31] The fully regulated model is also referred to as the Regulated Asset Base (RAB) model in other parts of the present report.

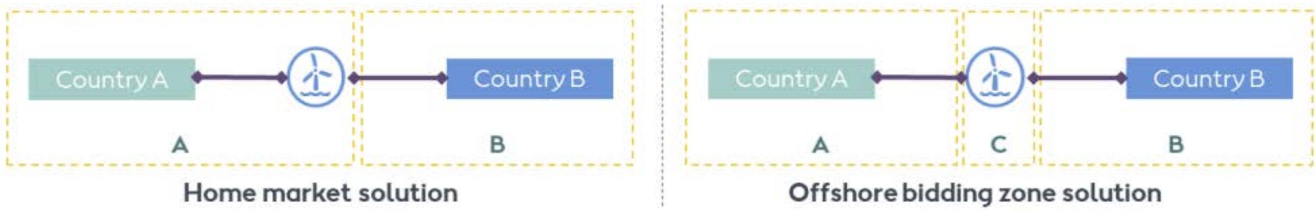
[32] According to a report by ACER (2022b), in 2021 congestion income collected by TSOs in EU Member States was allocated in the following manner: 45% on priority objectives, 49% was saved in a separate internal account, 5% was used for tariff reduction and 1% was paid on taxes.

Recommendations on the market design

At the operational stage, total remuneration of hybrid projects is the sum of congestion rent earned by the transmission asset owner and electricity sold at the electricity market. Under the home market setup (see left-hand side in Figure *43* for a hypothetical setup) in which ORE generation is radially connected, producers capture the price of the bidding zone to which the producer is linked – in this case the price at bidding zone A. In Figure *43*, the line between ORE generation and country A is internal to bidding zone A, while the owner of the line (e.g., a TSO or an OFTO) between the ORE generator and country B captures congestion rent.

In contrast, in the OBZ setup (see right-hand side in Figure *43*), the price captured by the ORE generator is the one at the zone at bidding zone C, which tends to be lower than in the home market setup. Congestion rent is earned by the transmission asset owners at both sides of the offshore bidding zone.

Figure 43: Two market design solutions for ORE projects



Source: Orsted (2020)

Recommended policy instrument: Bidding zone review under the Electricity Regulation and the CACM regulation

Articles 32 and 34 of the existing CACM GL Regulation establishes the procedure to review bidding zones, which means that the process for reviewing bidding zones exists already (see Box 1 on this matter). This process can be initiated by a Member State, an NRA, or a TSO.

Furthermore, article 14(7) of the Electricity Regulation (2019/943) clearly establishes that based on the identification of structural congestion by a TSO, a Member State may either implement an action plan or review and amend the existing bidding zone configuration.

In summary, the concerned Member State is competent to establish a new OBZ in its territorial waters or the exclusive economic zone. However, if establishing a new OBZ raises concerns and disputes, the process could become slow and bureaucratic.

The emergence of a meshed offshore grid will likely require a revised procedure and the development of more specific guidelines and policies, but unilaterally deciding on the establishment of an OBZ is something that Ireland has the prerogative to implement.

The review of the bidding zone configuration may interact with Ireland's existing Designated Maritime Area Planning (DMAP) process, which determines the broad area where ORE projects can be developed. An initial, broadly defined area is further refined through a process of public engagement and consultation, expert environmental impact assessments and other expert analysis of the maritime areas, to assess the area's suitability for ORE development (DECC, 2023a).

Recommended policy instrument: Develop appropriate de-risking instruments for commercial actors (generation)

These may range from forward contracts, financial transmission rights to Power Purchase Agreements (PPAs) and Contracts for Differences (CfDs) or the recently debated Transmission Access Guarantee (TAG). The specific choice of instruments depends to a considerable extent on the result of the ongoing EU debate on ORE policy and regulation at the EU level.

Recommended policy option: Set a date and a plan to implement OBZs

In line with the recommendation to anticipate investments to enable the gradual emergence of hybrid interconnections which ultimately lead to a meshed offshore grid (see recommendations on transmission planning), it is recommended that a proactive plan for the introduction of OBZs is established as follows:

Before 2030 or until Phase 2 is completed:

iii) Radial connections can be assumed. In this case, connections to shore are internal transmission lines.

iv) Generation is remunerated according to the HM design.

After 2030 (or the 5 GW target is reached):

When hybrids are part of ORE project solutions:

iii) establish OBZ for generation and with one point of the hybrid connected to OBZ, the other point connected to another bidding zone/country

iv) accompany the introduction of OBZs with appropriate and non-distorting de-risking measures, such as CfDs, PPAs.

Opted-out policy option: proceed with status quo (radial connections belong to a home market)

The alternative policy option is to proceed with status quo, meaning that all ORE generation is connected to the home market. To enable flexibility to this setup, a clause in the connection agreement could establish that the market design setup may later change to an OBZ, if an offshore hub is connected via a hybrid interconnector, or there emerges a new connection to another country. However, this carries the disadvantage that it increases the risk in the framework conditions of offshore wind.

Table 10: Summary of policy recommendations on the market design

Policy instruments	Recommended policy/regulatory option	Opted-out policy/regulatory options
When relevant proposing a bidding zone review (present EU process considered in CACM regulation should be improved and become more efficient)	**Before 2030:** Radial connections can be assumed (home market zone) **After 2030 (or the 5 GW target is reached):** when hybrids are part of ORE projects: i) establish generation in OBZs	Establish hybrids within home market zones Proceed with status quo (radial connections belong to a home market). Generation is remunerated according to the home market zone.
De-risking instruments for commercial actors (generation)	ii) accompany the introduction of OBZs with appropriate and non-distorting de-risking measures, such as CfDs, PPAs	Being neutral with respect to the risk issues faced by the commercial actor

2.6 Concluding remarks on the recommended policy framework for hybrid interconnections

In this chapter, four main policy and regulatory recommendations for the development of a hybrid interconnection policy for Ireland have been presented:

- With regards to **transmission planning**, as policy instrument, it is recommended to introduce an **Offshore Transmission Strategy, which includes a holistic design approach for onshore and offshore network development**. This integrates both onshore and offshore network development and includes cost/benefit scenarios and analyses of hybrid interconnection viability in cooperation with the most relevant countries for Ireland. Besides offshore grid development, this planning framework must incorporate and determine the required onshore network reinforcements and expansions resulting from developing the offshore network. Furthermore, as policy stance, it is recommended to enable a gradual development of hybrid projects by means of an anticipatory investment approach in cases where evidence indicates the potential emergence of a hybrid rather than a radial interconnection.
- With regards to **international cooperation**, the choice of instrument depends on the level of mutual understanding and may range from a letter of intent to a memorandum of understanding. However, the recommendation on policy stance is that a proactive approach to the establishment of bilateral political and technical cooperation is implemented.
- With regards to the **financing model for hybrid transmission assets**, which is a regulatory rather than a policy topic, Ireland has experience in the implementation of both fully regulated investments as well as partly regulated investments (the Cap and Floor model) for point-to-point interconnectors, which means that the country will not need to create a completely new framework. However, as policy stance, it is recommended that instead of committing to one single approach, there is clear openness to the cap and floor regime given the need to attract investors who are willing to take risk level, as well as the symmetry with the regime for hybrids in the UK, which is expected to be a cap and floor regime too.
- With regards to the **market design**, Ireland has the possibility to unilaterally introduce OBZs given the existing EU regulatory framework which gives member states this prerogative. Regarding the policy stance, it is recommended to announce an orderly introduction of OBZs. One possibility could be to set 2030 (or the 5 GW milestone) as a set date for OBZs, before which the home market approach could be implemented. Providing a clear message to developers will increase certainty.

3. RECOMMENDATIONS ON COST RECOVERY MODELS FOR HYBRID INTERCONNECTIONS IN IRELAND

3.1 Assets, costs, and revenues in a hybrid project

As mentioned earlier in this report, hybrid interconnections are electricity infrastructure that serve the dual purpose of connecting ORE generation to shore and interconnecting two or more bidding zones. To provide precision, ENTSO-E (2022) has proposed the following delimitation of assets (see Figure 44):[33]

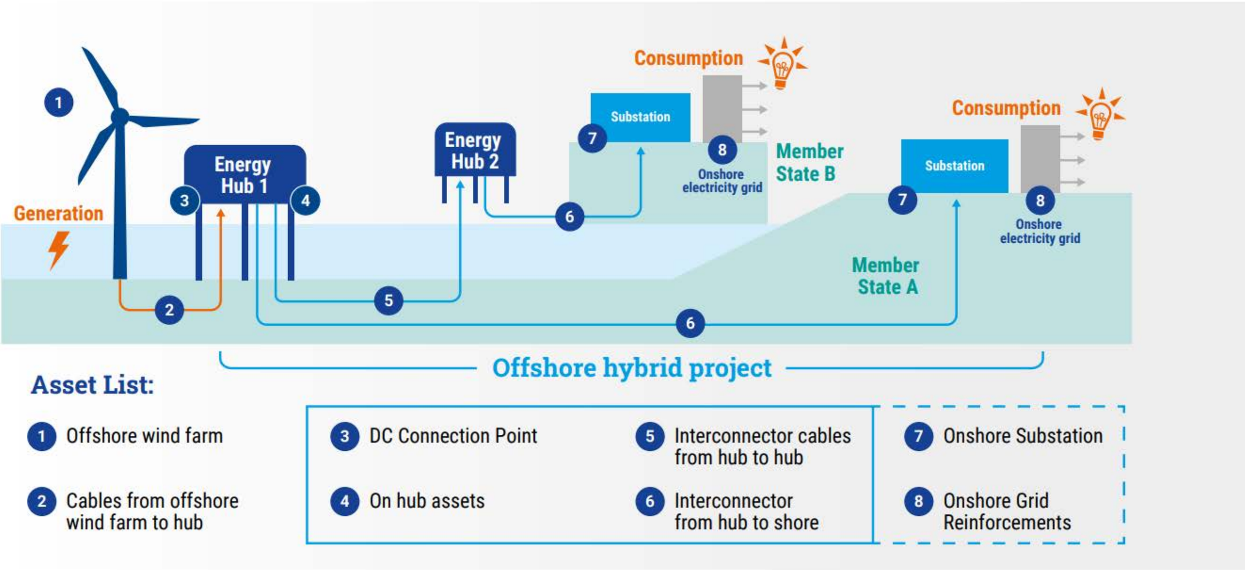
- ORE generation (numbered with 1) is - as any other electricity generation asset - owned and operated by a commercial party.
- The cable connecting ORE to the energy hub (numbered with 2) may be established by the operator itself or a TSO, but its operation is outside the ORE producers' responsibility. Following EU unbundling rules, a party different from the ORE generator operates the transmission assets. For example, an OFTO.
- The offshore hub/DC connection point (numbered with 3) is the physical space connecting one or several ORE generation units to the backbone transmission system. It contains equipment such as converters and transformers (numbered with 4) and its design can be in different ways (sand island, jacket, floating).
- Transmission assets (numbered with 5 and 6) are either cables connecting offshore hubs or a hub to an onshore system. The defining characteristic is that these assets cross national borders and/or bidding zones.
- Onshore connections and equipment (numbered with 7 and 8) include converter stations, substations as well as expansions and reinforcements on the onshore grid.

It is clear from the depiction that such projects span several activities – generation and transmission both onshore and offshore – with costs and benefits accruing to the different stakeholders involved.

To simplify, costs can be broadly divided into transmission and offshore ORE generation costs (see Figure 45). Within the first category, a further distinction could be made between offshore and onshore grid costs. However, in a strict sense, onshore costs are not part of a hybrid project but constitute instead an indirect cost to the offshore hybrid project. Regarding revenues, a combination of transmission tariffs and congestion income usually finances transmission costs, while offshore generation costs are recovered through a combination of market revenues and state support. Within this framework, directly involved stakeholders are TSOs or transmission asset owners (such as the OFTO in the British model) and ORE developers. More broadly, the state - which grants state support - and by extension both taxpayers and electricity network users are part of the group of stakeholders involved.

[33] From ENTSO-E's perspective, "an offshore hybrid project refers specifically to the transmission assets, serving the dual purpose of connecting offshore RES generation and interconnecting two or more bidding zones". From a transmission asset operation and ownership perspective, assets in a hybrid project include numbers 3 to 6 in Figure *44*, but may include also 7 and 8 depending on the applicable regime (ENTSO-E, 2022).

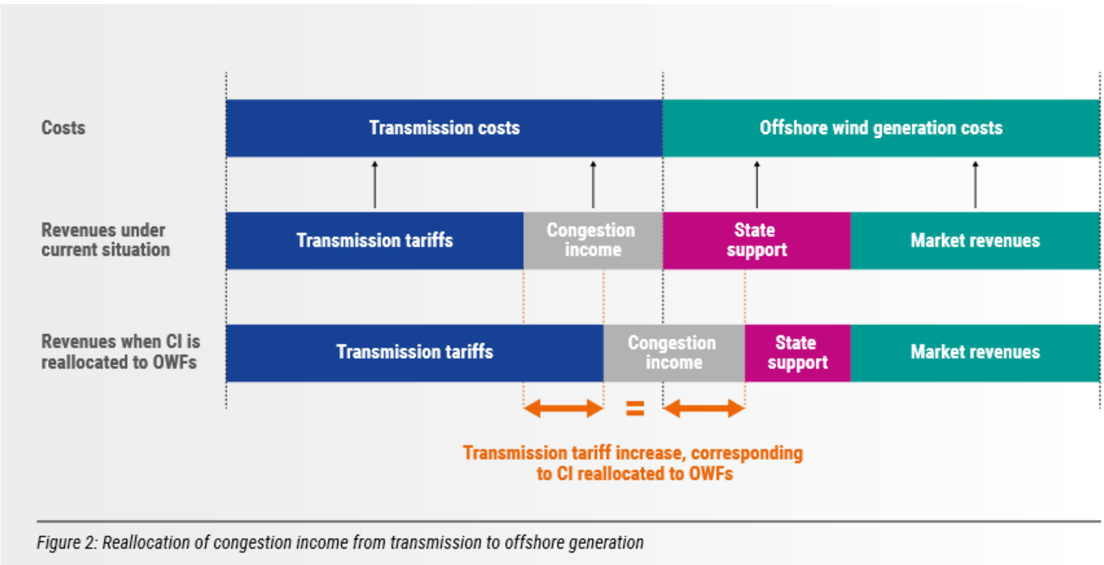
Figure 44: Overview of assets in a hybrid project



Source: ENTSO-E (2022)

Figure 45 also shows graphically the impact of re-allocating congestion income from TSOs to ORE generators as a measure to mitigate the revenue risk they perceive, as was initially proposed by the European Commission (2020) in its strategy to harness the potential of offshore renewable energy. By transferring congestion income, which is earned by TSOs, state support expenses would be lower but – as the figure shows – this would lead to higher tariffs charged on electricity networks users. Effectively, a zero-sum game. Furthermore, re-distributing congestion income amounts to cross-subsidization of ORE generators by TSOs.

Figure 45: Cost and revenue sources in hybrid projects



Source: ENTSO-E (2021)

3.2 Review of ongoing proposals on cost recovery mechanisms

Despite the abundance of analyses on hybrid projects, only a handful of countries has presented detailed cost recovery mechanisms which go into the details of both the regulatory framework to recover transmission costs and the market design environment in which the ORE generator will operate. Two notable exceptions are Denmark and the UK where respectively Energinet (Denmark's TSO) and Ofgem (GB's energy market regulator) have consulted on both the financing framework of transmission assets and the market design framework to be implemented. In what follows, this report reviews the main characteristics of the proposed models in Denmark and the UK.

3.2.1 Denmark's Energy Island producer tariff methodology

In Denmark, the Danish TSO Energinet proposed a tariff method to cover the costs caused by an ORE production facility connected at an energy island (Energinet, 2023). As per the formal definitions in the proposed method, this producer feeds in electricity to the grid from a production facility connected at an energy island, which may be either an existing or artificial island. According to the method, the energy island's defining characteristics are that it is not a primary offtaker of the energy produced and that it is connected to shore via two or more connection points in different bidding zones. Thus, an energy island is defined from the outset as a hybrid interconnector since it serves the double purpose of transporting electricity to shore and linking two or more bidding zones and/or countries. It follows from the definitions in Energinet's proposed method that energy islands will be located at their own bidding zones, that is OBZs. This specific point in the proposed methodology clarifies the question on the foreseen market design approach to hybrid interconnections.

The method proposed by Energinet distinguishes among three main cost causation categories - connection, feed-in, and balancing. Connection tariffs consider either a full or partial cost pass-through on the energy island producer (see Table 11), while injection and balancing follow overall tariff policy defined by Energinet.[34] Specifically, the feed-in tariff will be the one charged on producers located in a generation surplus area. Overall, the Energy Island producer must be within a range of 0-1,2 EUR/MWh in accordance with EU Regulation (838/2010) on inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

Within the connection cost category, there is **full cost pass-through** on the producer in relation to expenses on High Voltage Alternating Current (HVAC) stations and facilities to connect to the station on the energy island, including station areas. The same applies to High Voltage Direct Current (HVDC) transmission stations as well as converters on energy islands related to the energy island producers' connection.

In contrast, **connection costs with partial pass-through** are categorized into three possible uses of the transmission infrastructure:

- **Evacuation capacity:** this is the share of transmission capacity used to bring produced ORE to shore and is estimated as the expected energy produced in a given calendar year divided by the total connection capacity of the energy island. This is an ex-ante calculation in which all energy produced on the island forms the basis to estimate the capacity usage, which is charged on the energy island producer.
- **Cross-border trade capacity:** this is the share of transmission capacity used for cross-border trade and is estimated ex-post, as the capacity that remains after all ORE produced on the island has been transported ashore. The share of this capacity usage charged on the producer is equal to zero, as other

[34] As part of an ongoing and comprehensive tariff reform process, since 1 January 2023 Energinet charges geographically differentiated tariffs on producers, based on both grid feed-in and balancing. The reform process also includes tariff reforms to incentivize co-location of consumption and production to enable and facilitate the emergence of sector coupling business models, such as Power-to-X (Energinet, 2022)

network users will benefit from its availability. Specifically, it will be consumers located in the bidding zones adjacent to the energy island who – according to the proposed method - will pay for this capacity usage.

- **Un-used capacity**: this is the capacity that remains unused once evacuation and cross-border capacity are deducted and is fully charged on the energy island producer.

Table 11: Cost pass-through on the connection component in Denmark's energy island tariff

Pass-through	Covers
Full	• HVAC/HVDC stations, • station areas, • converters
Partial	• Connection to DK shore, • connection to foreign shore (depends on ownership/cost sharing agreement between TSOs)

Source: based on Energinet (2023)

Preliminary estimations of capacity shares

Preliminary estimations done by Energinet based on the planned energy islands (North Sea and Bornholm), show indicative preliminary figures for the share of connection costs that will be charged on the energy island producer and the remaining network users (see Table *12*).

With respect to Energy Island Bornholm (EIB), the estimations are based on the following assumptions:

- 3 GW ORE capacity connected at EIB
- 1,2 GW transmission capacity on the interconnection between EIB and East Denmark (bidding zone DK2)
- 2 GW transmission capacity on the interconnection between EIB and Germany

And with respect to Energy Island North Sea (EINS), the underlying assumptions are:

- 4 GW ORE capacity connected at EINS
- 2 GW transmission capacity on the interconnection between EINS and West Denmark (bidding zone DK1)
- 2 GW transmission capacity on the interconnection between EINS and Belgium

As capacity shares to be used in the proposed methodology will be estimated based on each individual interconnector, for each operational hour, Table *12* indicates the expected capacity shares divided by purpose, assuming a 50/50 weighing on each flow direction. For example, this means that in a given year, 54% of the available capacity will be used to evacuate production on the island between EINS and West Denmark, while 33% of the time this interconnector will be used as cross-border capacity and 13% of the time capacity will remain unused. Based on this assumption, the energy island producer will be charged 67% of the connection costs while the remaining 33% will be covered by consumers.

Table 12: Cost pass-through on the connection component in Denmark's energy island tariff

Hybrid project	Interconnector	Evacuation	Cross-border	Unused
Energy Island Bornholm	EIB – East Denmark (DK2)	49%	39%	12%
	EIB-Germany	49%	23%	28%
Energy Island North Sea	EINS – West Denmark	54%	33%	13%
	EINS - Belgium	54%	33%	13%

Source: based on Energinet (2023)

Futher considerations

In Denmark's proposed method, a principle of **proportionality** applies, meaning that if there are several energy island producers connected to the energy island **in the same bidding round**, costs are distributed proportionally to their feed-in capacity.

Furthermore, the method also considers the possibility of reducing costs charged on the energy island producer based on contributions made by the foreign TSO and/or EU funding obtained. In the analysis made by Energinet, it is assumed that 50Hertz (German TSO) is covering all costs on the interconnection between EIB and Germany and that Elia (the Belgian TSO) covers half of the costs on the interconnection between EINS and Belgium.

3.2.2 GB's ongoing consultation on the Regulatory framework for Offshore Hybrid Assets

Following the pilot regulatory framework organized by Ofgem in 2022, two MPI projects – one to Belgium (Nautilus) and another one to the Netherlands (LionLink) – progressed and were granted interconnector licenses by Ofgem on 14 July 2023[35]. In the coming stages of project development, a specific regulatory regime will be developed for these.

Following the initial MPI pilot framework, Ofgem is consulting on the enduring regime for MPI projects. In two open consultations, Ofgem has outlined several options for both the market arrangements and the regulatory regime. In these parallel consultation processes, Ofgem has clarified its preferred options and views which are as follows:

- The existing **licensing framework** should be modified to account for the different possible configurations of hybrid projects, which is why Ofgem has broadened its previous definition of MPIs to the more general Offshore Hybrid Assets (OHAs) categorization (see Figure *39* in Chapter 1). Within OHAs, Ofgem recommends distinguishing between MPIs which – as previously defined – connect ORE to shore and interconnect two jurisdictions and/or bidding zones. In addition to MPIs, non-standard interconnectors (NSIs) serve the same double purpose as MPIs but, unlike MPIs, ORE generation is located outside the GB market and thus are only conducting interconnection activities in GB. Ofgem

[35] Licenses are an authorization to operate an electricity interconnector but are neither authorizations to construct the infrastructure nor a commitment to a specific regulatory regime.

indicates that a new licensable activity for MPIs must be created, and that the existing interconnector licensing framework with modifications accounts is sufficient for NSIs.

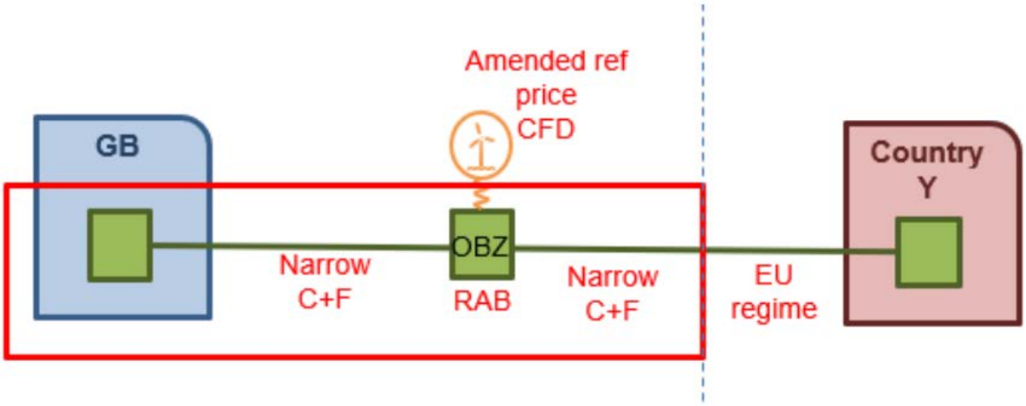
- Regarding the **regulatory regime for OHAs**, Ofgem proposes six principles to underpin its choice of regulatory regime:
    - Economic viability: the project should be commercially viable
    - Integration in energy system: the wider benefit of the project, including market integration, security of supply, congestion management shall be considered
    - Consumer protection: consumer interests should be protected through the avoidance of excessive costs and the granting of market power to OHA operators
    - Cost and revenue alignment: costs and benefits will be balanced such that a fair risk and reward profile between the relevant parties is obtained
    - Coordinated regulatory treatment: the regulatory regime will be coordinated with fellow NRAs located in the partner country's jurisdiction
    - Level playing field: the regime should attract third parties and unbiased towards incumbent TSOs and non-TSO developers
- Ofgem recommends a "compartmentalized" approach in which a combination of cost recovery mechanisms finance the two main elements of OHAs. Specifically, Ofgem recommends a **Regulated Asset Base (RAB)** model – which secures a fixed return on the investment- for the platform component of the project and a **"narrow" Cap and Floor** for the cable component of the infrastructure, operating under a single license.[36] According to this revenue model (see Figure *40* in Chapter 1), the minimum revenue stream should be raised while the maximum level should be lowered This approach would keep the main incentive features of the model unaltered while providing increased certainty to the investor. In its recommendation, Ofgem argues that the nature of OHAs would significantly alter the Cap and Floor design. On the one hand, a higher floor would be required, diminishing the developer's ability to earn a return above the floor. On the other hand, the basis of the cap and floor is a variable revenue stream (congestion rent) which the platform component does not generate.

- Figure *40*Another important aspect of Ofgem's consultation is its recommendation to compensate the ORE generator with an amended Contract for Difference (CfD) in which the reference price is the OBZ price rather than the price onshore. With this recommendation as background, Ofgem is already clarifying that its preferred market design is the OBZ solution.

Ofgem's overall recommendation can be graphically summarized in Figure 46 in which the platform's cost is recovered through a RAB model, the cable is subject to a narrow Cap and Floor and the ORE developer obtains an amended CfD, in which the reference price is the one at the OBZ. Note that the recommendation for the usage of a narrow cap and floor applies as well to the category of NSIs.

[36] Ofgem's RAB model corresponds to what elsewhere in this report has been referred to as a "fully regulated" model (see for instance
Table **6** for a comparison of best practices).

Figure 46: Graphical summary of Ofgem's recommended regulatory and market design framework



Source: Ofgem (2023)

Further considerations on Ofgem's regulatory and market design options

A relevant insight that can be obtained from Ofgem's consultation is the functioning of regulatory and market design models considered and analysed but not recommended, as this provides an understanding of the available options. Overall, Ofgem distinguishes between two broad categories of regulatory regimes: the ones based on a Regulated Asset Value (RAV) and the ones based on an Internal Rate of Return (IRR) - see Figure 47 for an overview.[37]

Within the RAV family, the OFTO model follows a Tender Revenue Stream (TRS) with competition, as developers compete to obtain the right to operate the offshore transmission asset based on a process in which developers reveal the sum of revenue streams to be obtained throughout the lifetime of the project. In contrast, the Cap and Floor regime – which is used for point-to-point interconnectors – is established relative to a variable, market-based revenue stream, such that the floor allows the developer to recover its costs (including a notional cost of debt) and in line with the cost of equity, the cap sets the maximum congestion revenue that a developer is allowed to obtain on a yearly basis. If revenues are below the floor, then the developer obtains a payment and if the revenue exceeds the cap, the developer pays back.

Both the TRS model with competition and the cap and floor model intend to introduce incentives to compete, innovate and bring about benefits to consumers that would otherwise be absent. In practice, they are variations to the RAB model, which both isolates investors from revenue risk and is easier to administer. However, unlike the Cap and Floor regime, the RAB lacks the incentive given to investors to target borders with structural price differences and to operate at maximum efficiency, thereby minimizing outages.

For the development of hybrid projects, Ofgem considered several variations to the existing models (see Figure 47):

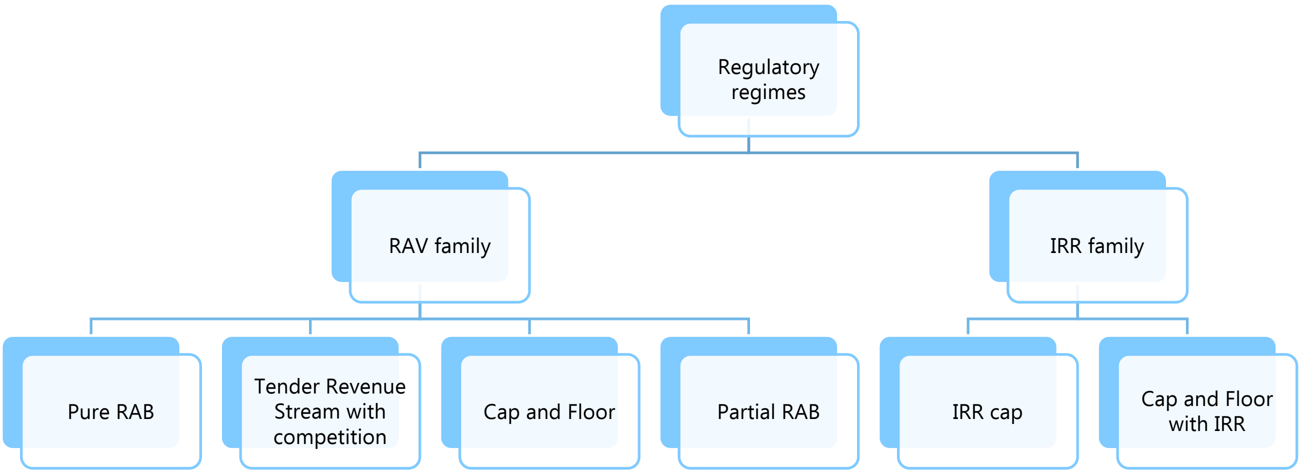
- **Partial RAB/cap and floor:** this is a combination of regimes, in which the shares of usage of the infrastructure in "transmission" or "interconnector" modes are measured on the basis of actual flows. The share used in transmission mode earns a fixed return while the part used as interconnector is remunerated under a cap and floor regime.
- **Cap and Floor with IRR**: in this variation, instead of a notional cost of debt and equity, the IRR is used to determine both the floor and the cap. The cap would be set as the target IRR rate plus an allowed

[37] For the sake of completeness, a RAV is an asset valuation assessed and approved by Ofgem while the IRR is the rate at which a project breaks even.

percentage over the rate of return and the floor is set as an IRR that allows bankability: enables debt repayment.

- **Narrow cap and floor**: as described before, in this variation the spread between the cap and the floor is reduced. To achieve this, one approach would be an adjustment based on an adjustment factor requested by the OHA developer and decided by Ofgem. As the adjustment factor is applied, the regime approaches the RAB model.

Figure 47: Overview of revenue and investment return regimes

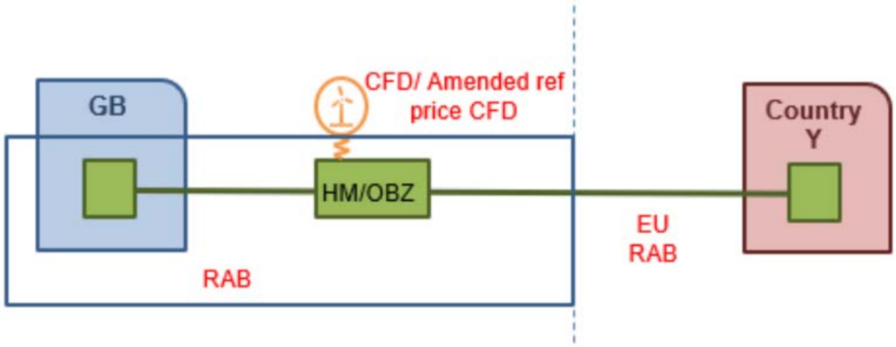


Source: based on Ofgem (2023)

As an alternative to the recommended regulatory and market design option (Figure 46), Ofgem considered five potential regulatory packages – which comprise both the transmission asset and the market environment - for the MPIs:

- **RAB for the combined assets of the MPI** (Figure 48): under this package, the entire asset is remunerated with a RAB model and the market environment remains open. If there is a HM, the existing CfD would be employed but in the case of an OBZ an amended CfD with reference to the OBZ price would be implemented.

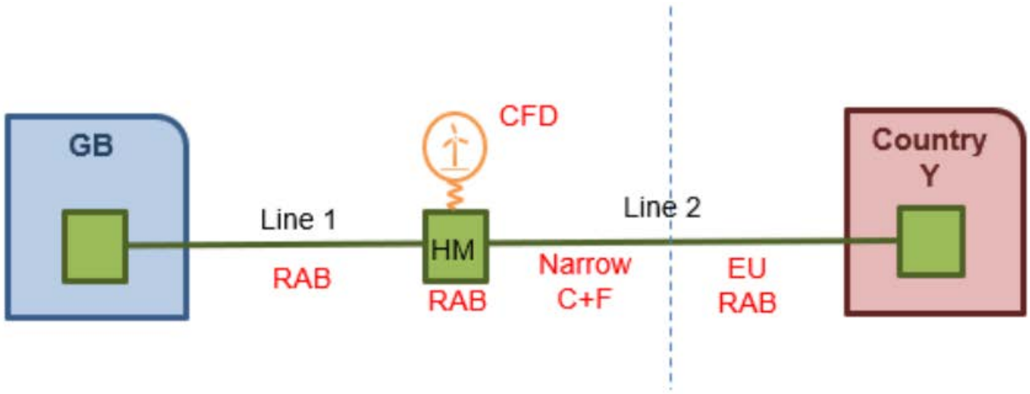
Figure 48: Ofgem's regulatory package 1 – RAB for the combined assets



Source: Ofgem (2023)

- **HM with narrow cap and floor** (Figure 49): in this package, a HM market design is assumed and accordingly both the transmission line and platform are remunerated with a RAB. The ORE developer obtains a CfD with reference to the HM. The MPI is compensated with a narrow Cap and Floor.

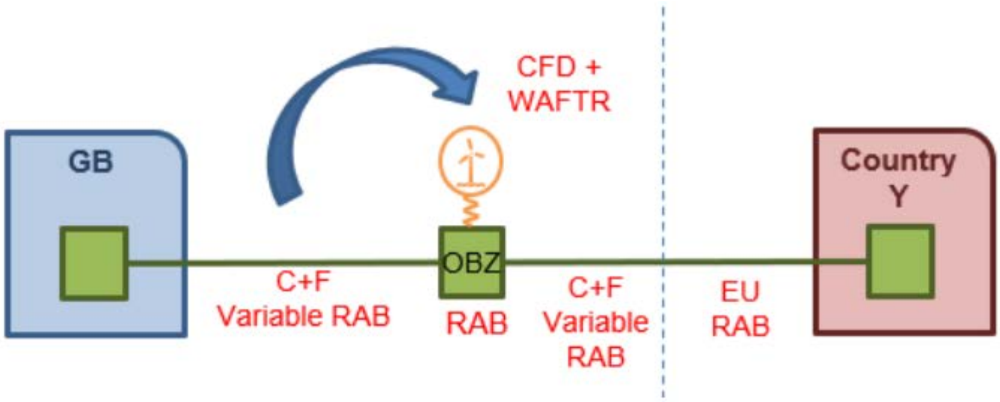
Figure 49: Ofgem's regulatory package 2 – HM with narrow Cap and Floor



Source: Ofgem (2023)

- **OBZ with partial RAB/cap and floor and Wind Adjusted Financial Transmission Right – WAFTR** (Figure 50): under this package, implementation of an OBZ is assumed. The cable obtains a partial RAB/cap and floor model while the platform obtains a RAB revenue. Further, the ORE developer obtains a conventional CfD in addition to a WAFTR, which is an ex-post redistribution mechanism in which the ORE obtains the revenue equivalent to the HM model, based on actual generation and the price difference between HM and OBZ.

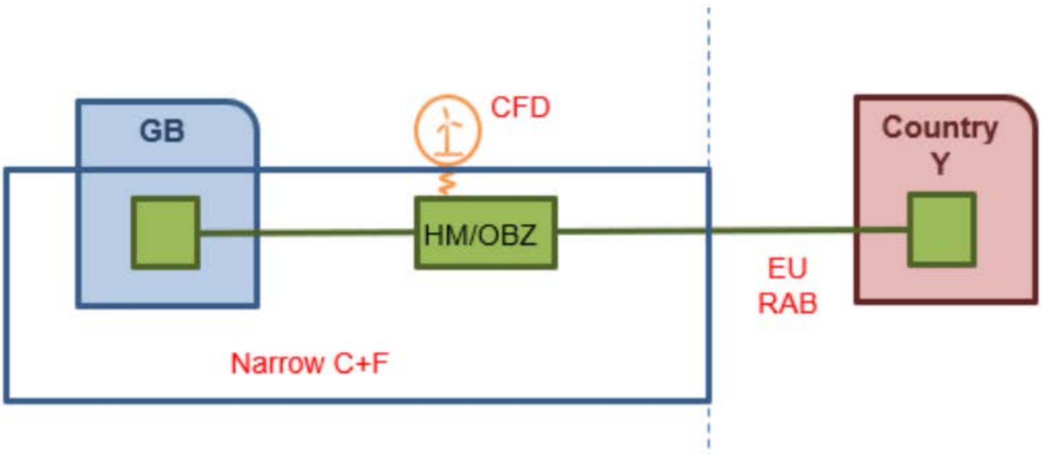
Figure 50: Ofgem's regulatory package 3 – OBZ with partial RAB/cap and floor and WAFTR



Source: Ofgem (2023)

- **Narrow cap and floor and amended CfD** (Figure 51) under this approach, which is applicable under both an OBZ and a HM design, a narrow cap and floor is applied to the entire asset, including the platform. The applicable CfD would be amended if an OBZ is implemented

Figure 51: Ofgem's regulatory package 5 – Narrow cap and floor for the whole asset

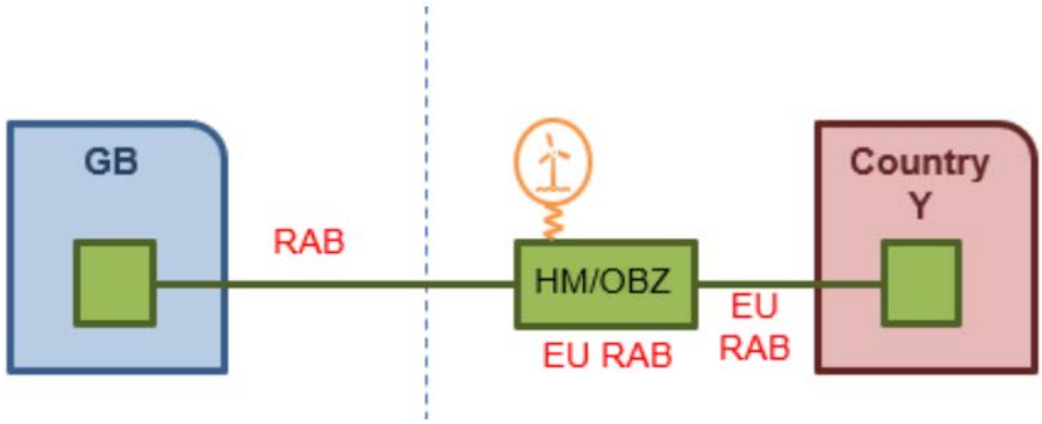


Source: Ofgem (2023)

In addition to the preferred option for NSIs, Ofgem considered an alternative model:

- **NSIs with RAB** (Figure 52): this option is considered regardless of the market design model chosen in the neighboring country, either an OBZ or a HM. In any case, the developer would earn revenue based on a RAB model and the congestion rent created would not accrue to the developer.

Figure 52: Ofgem's regulatory package 7 – NSIs with RAB



Source: Ofgem (2023)

3.2.3 Comparative analysis

A comparison between the recommended Danish and British framework highlights one major point of coincidence: both countries foresee that the market design solution for future hybrid projects will be the OBZ framework.

However, the policy stance on the financing of the transmission infrastructure and the approach to state aid differs significantly. With regards to state aid given to ORE producers:

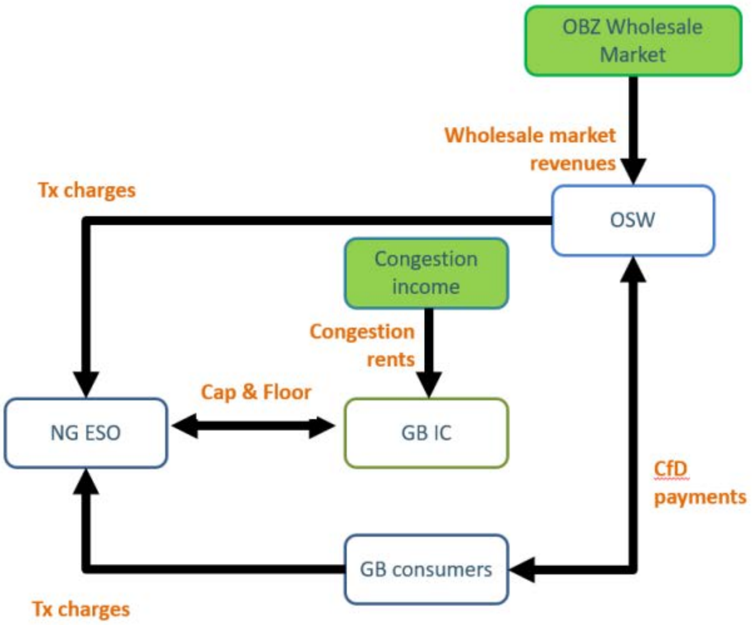
- In the UK, the ORE developer is expected to earn CfD payments – either as the instrument is presently designed or as an amended version of the existing mechanism, which means that GB consumers will underwrite the ORE generation investment (Figure 53). In contrast, Denmark will not provide state aid to the ORE producer (see Figure **54**).

With regards to the financing model for the transmission infrastructure:

- In the UK, Ofgem recommends a model with an RAB model for the platform together with a narrow cap and floor for the cable (see Figure 46) which in practice means that GB consumers will also finance a sizable share of the transmission infrastructure. In Denmark, the energy island producer tariff methodology materializes the condition (established in Denmark's parliamentary agreement) that most costs for the electricity transmission infrastructure shall be transferred to the ORE developer and a minority of these to electricity consumers.[38]

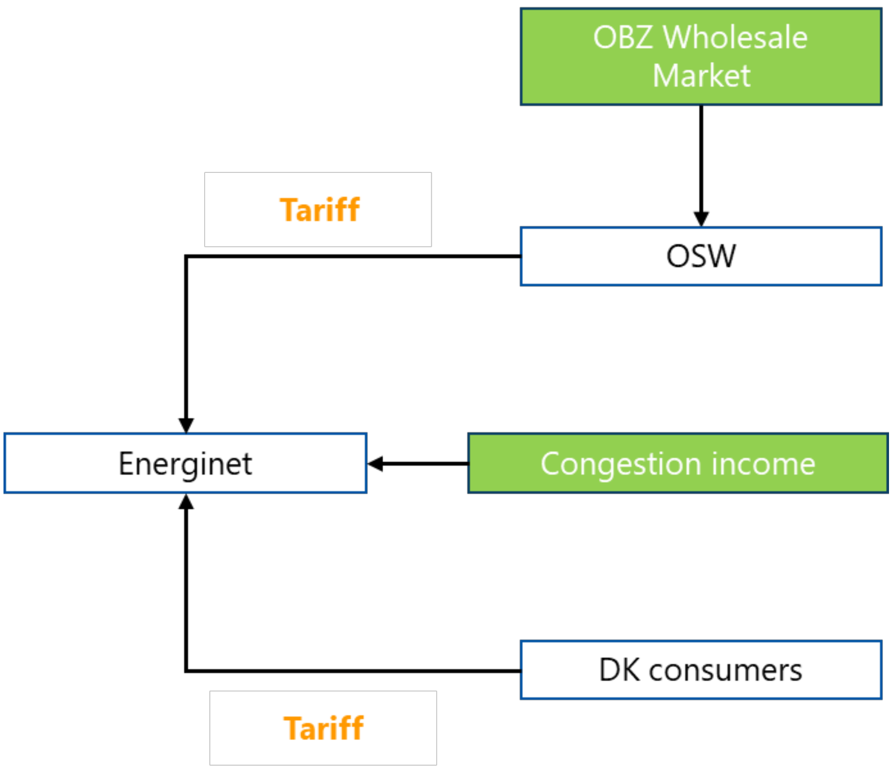
[38] However, in the specific case of EIB, a follow-up parliamentary agreement established that state aid will be given to finance the interconnector between EIB and East Denmark as well as its share of the platform (offshore hub). In contrast, a complete revision of EINS has been initiated, as it does not live up to the requirement that hybrid projects must be profitable.

Figure 53: Revenue flows for existing offshore wind farms and interconnectors in GB



Source: Ofgem (2023)

Figure 54: Revenue flows for forthcoming energy islands in Denmark



Source: Authors' own interpretation of Danish policy decisions

3.3 Ensuring regime compatibility

There exist several examples of transmission infrastructure developers with diverging cost recovery mechanisms which nonetheless coexist in a single cross-border transmission infrastructure project. Point-to-point interconnectors may be subject to one type of cost recovery mechanism on one end of the interconnector, while a different regime is applied in the neighbouring jurisdiction.

To illustrate the point, Table 13 shows the list of electricity interconnectors with a Cap and Floor regime approval by Ofgem for operation in the GB market. In the partnering country, many of these projects are regulated under a different financing model – frequently, the fully regulated model (also known as the RAB model) applied by most EU Member States. A case in point is the Viking Link which, on the Danish side is a fully regulated investment by Energinet and as shown in the table operates under the Cap and Floor model in the UK.

Table 13: List of interconnectors with Cap and Floor regulatory approval by Ofgem

Project name	Developers	Country	Capacity (GW)	Date
Nemo Link	NGIH and Elia	Belgium	1	2019
IFA2	NGIH and RTE	France	1	2021
NSL	NGIH and Statnett	Norway	1,4	2021
Viking Link	NGIH and Energinet	Denmark	1,4	2023
Greenlink	Element Power & Partners Group	Ireland	0,5	2023
GridLink	iCON Infrastructure Partners III, L.P.	France	1,4	2024
NeuConnect	Meridiam, Allianz and Kansai Electric Power	Germany	1,4	2024
NorthConnect	Agder Energi, Lyse, E-CO and Vattenfall	Norway	1,4	2025
FAB Link	Transmission Investment and RTE	France	1,4	2025

Source: Ofgem (Ofgem, 2023b)

From a legal perspective, there are basically no limitations on the establishment of agreements between companies developing point-to-point interconnectors or hybrid interconnectors across jurisdictions. Following with the Viking Link example, the interconnector is 50/50 owned by National Grid Viking Link Limited (NGVL) and Energinet. NGVL, which is fully separated from the rest of the National Grid group, is a subsidiary of National Grid Interconnector Holdings. At the beginning of the project, Energinet and NGIL entered into a cooperation agreement which was later substituted by a Joint Development Agreement (JDA) valid until the Final Investment Decision (FID) stage. The JDA was subsequently superseded by a Joint Venture Agreement (JVA) which comprehended a construction agreement for the interconnector as well as an Ownership and Operation Agreement (OOA) which outlines the operation and maintenance of the infrastructure. On many occasions, partners in interconnector projects establish special purpose vehicles (SPVs), which are companies established for a specific and limited purpose.

3.3.1 Incentive misalignment

However, it is the misalignment of incentives which may be among the major barriers to establishing hybrid projects. While TSOs - which in many cases are state owned - will typically consider the maximization of socio-economic welfare as their main objective, private developers focus instead on profit maximization. In the evaluation of projects, this means for example that a state-owned TSO under a fully regulated model may place a relatively higher value to societal benefits such as security of supply than what a private investor otherwise would under a market-based setup, such as the Cap and Floor or merchant model.

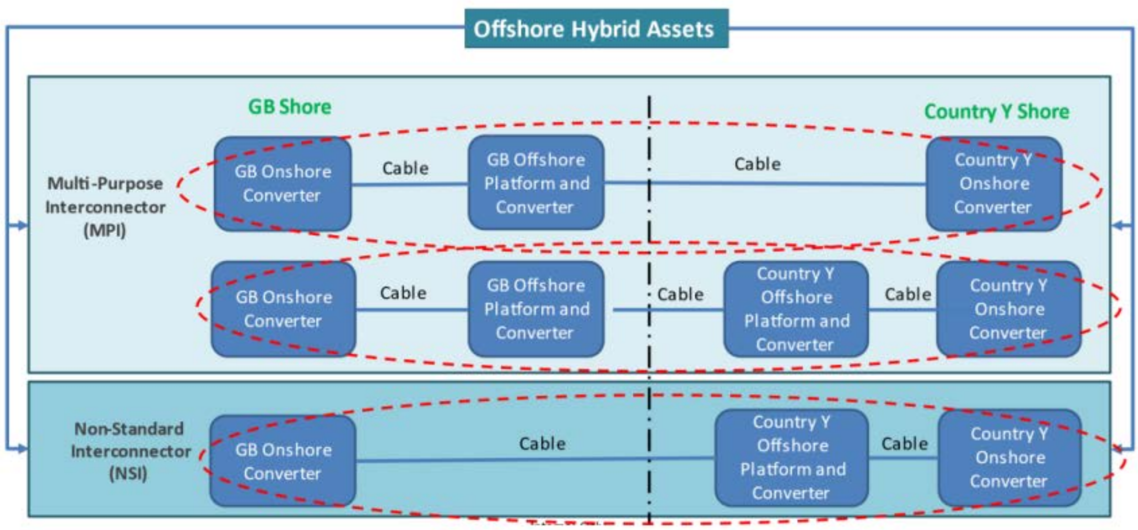
Under such models – as has been explained in the preceding sections - it is congestion rent which ultimately determines the revenue streams to be obtained by the investor. In consequence, not only are these investors incentivized to target bidding zones with structural price differences, but they are implicitly motivated to build up transmission capacity which could potentially be below the optimal level. To solve these issues, a robust regulatory framework, which balances benefits accruing to both the investor and to society is desirable.

This potential incentive misalignment becomes evident in Ofgem's preferred approach to cost sharing in OHAs (Ofgem, 2023a). According to them, a "system-to-system" sharing of costs and revenues should be implemented (

Figure 55). However, congestion rents may accrue asymmetrically depending on the price dynamics and there may also be different regulatory approaches at each side of the ORE generator. While Ofgem prioritizes a competitive approach, partnering countries may focus on a cost recovery mechanism designed specifically for the incumbent TSO.

Furthermore, on the EU side, article 19 of the Electricity Regulation 2019/943 establishes two primary objectives for collected congestion income, namely: a) ensuring the availability of cross-zonal capacity (including firmness payments) and b) maintaining and increasing cross-zonal capacity. In other words, the objective of collected congestion income is not meant to finance a specific project – as in the Cap and Floor regime – and has no validity outside the EU.

Figure 55: Cost and revenue sharing boundaries



Source: Ofgem (2023)

3.3.2 Possible solutions

There does not exist one single solution to align incentives between an EU Member State – such as Ireland - and the UK. Under any circumstances, establishing common ground requires both negotiation and coordination. However, one possible (rather pragmatic) approach for Ireland could be to proactively identify specific aspects in UK's regulatory approach which could fit well with Ireland's framework. For example:

- **Assigning one company the role of developer and operator in a similar way to the UK's OFTO model:** one way to re-align the incentives would be to design a cost and revenue sharing model in which one single company develops and operates the entire hybrid project across jurisdictions. This has the potential advantage of bringing about economies of scale and coordination which could be beneficial for both jurisdictions.

However, this approach presupposes a substantial coordination effort on state institutions involved to agree on the regulatory framework to be implemented, including the design of a coordinated tendering process to assign the developer and operator role and not least the applicable cost recovery mechanism.

Among other things, this approach may require a re-evaluation of roles, such that the incumbent TSO (EirGrid in Ireland's case) only retains its system operation role but allows for a third party to own the assets. Under such an approach, applying the Cap and Floor regime at both sides of the jurisdictions could be beneficial, as it would increase transparency and would facilitate the negotiation of the specific model to recover the costs.

3.4 De-risking measures

3.4.1 Risks for hybrid offshore projects

While offshore project developers are used to price and volume risks, the development of hybrid offshore projects changes the risk profile. Hybrid offshore projects potentially bring about significant net socio-economic benefits resulting from CAPEX and OPEX savings as well as increased utilization of the existing infrastructure.

- **Price risk**: In comparison to the HM solution, where the price is based on the electricity market in the onshore bidding zone, the price in OBZs is based on the 'marginal value' of neighbouring bidding zones to which there is no congestion. In case of congestion, i.e., in the case of a high wind scenario, these exposes ORE producers to the risk of capturing lower prices, and hence reduces the revenue of ORE producers (see Figure 36 under section 2.5 for a graphical explanation).
- **Volume risk**: ORE generators also face an increased volume risk, as they depend on the availability of cross-border transmission capacity to deliver their production, which may become unavailable due to outages – particularly, "deratings" which refer to instances when the capacity allocated to the market by TSOs is reduced to ensure system reliability (Laur et al., 2022).

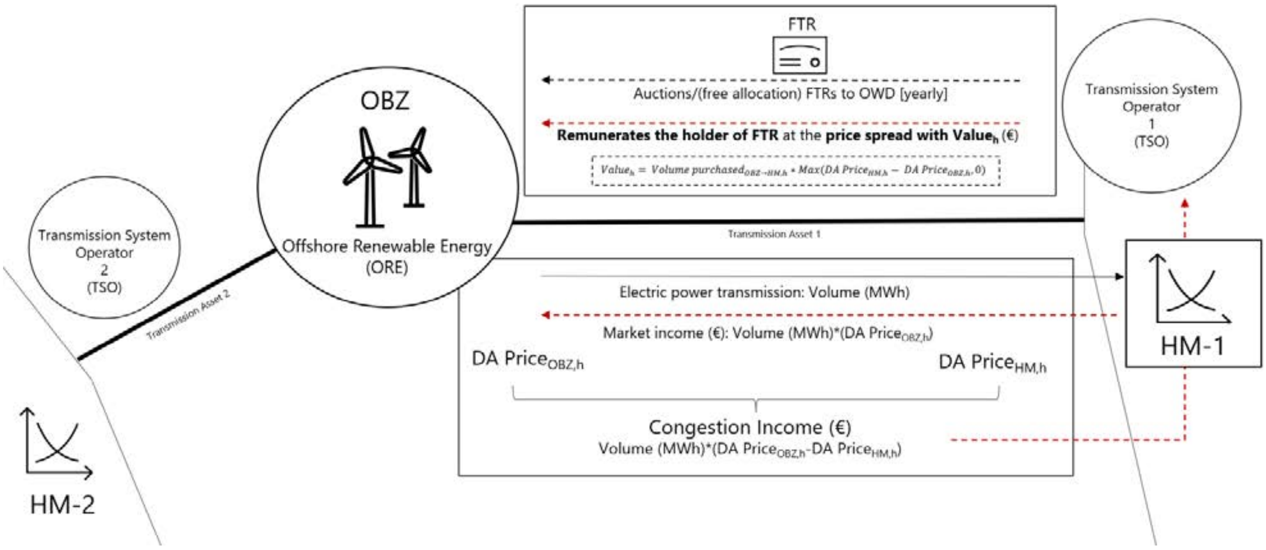
3.4.2 Mitigating the risks

Besides the traditional risk hedging measures that exist, such as Financial Transmission Rights (FTRs), Power Purchase Agreements (PPAs) and exchange-based contracts such as Electricity Price Area Differentials (EPADs), specific risk mitigation measures for offshore wind projects operating under OBZs are currently under development and discussion for regulatory approval. These are discussed in turn.

Congestion Income Financial Transmission Rights (CI-FTRs)

The locational risk between two adjacent bidding zones in a specific direction can be hedged with FTRs, which gives the holder the right to be compensated with the price differential. As it is a financial contract, there is no physical usage of the transmission capacity. In an FTR, TSOs guarantee the payment of the electricity price difference between the OBZ and the HM, hence compensating for the risk of a price difference between two zones.

Figure 56: Congestion Income Financial Transmission Rights (CI-FTRs)



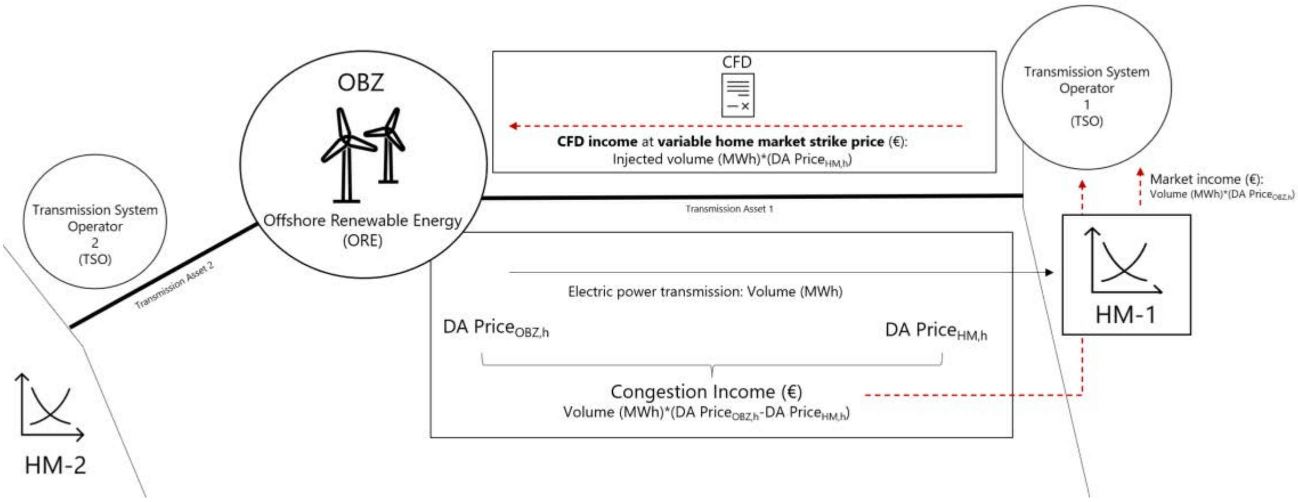
Source: Based on Laur et al. (2022)

While usual practice is that TSOs auction FTRs forward based on a fixed volume and remunerate the holders if the price spread is unfavorable, the idea of CI-FTRs as suggested by Laur et al. (2022) is that a priority allocation of FTRs is given to hybrid projects for free, possibly at the tendering stage. Figure *56* illustrates the functioning of a CI-FTR. The holder of the CI-FTR receives compensation in the amount of the difference between the onshore price (HM) and the OBZ price for the fixed volume. As this instrument is backed by the TSO, it effectively amounts to a re-allocation of congestion income.

Congestion Income Contracts for Difference (CI-CfDs)

CfDs are usually signed between government bodies and generators in the context of offshore wind auctions. By securing a 'strike' price for their generation, generators remove their price risk. In contrast to the conventional CfD, the TSO and the ORE generator are counterparties to this kind of contracts (see Figure *57*). Instead of a fixed strike price, CI-CfDs are signed in reference to the HM price as a variable strike. The ORE then receives the CfD income at the variable HM strike price for the electricity injected to the HM. The TSO in the HM receives a congestion income, which equals the difference of the Day-Ahead price in the OBZ and the Day-Ahead price in the HM for the volume of electricity supplied.

Figure 57: Congestion Income Contracts for Difference (CfDs)



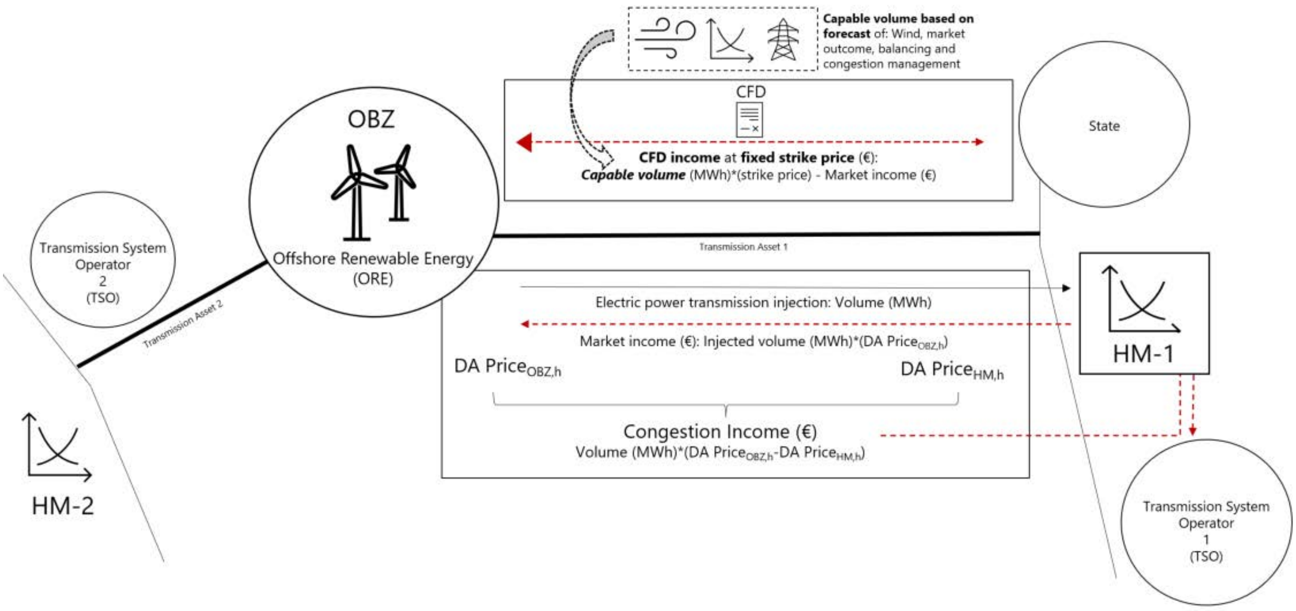
Source: Based on Laur et al. (2022)

Laur et al. (2022) note that both CI-CfDs and CI-FTRs tend to overcompensate the ORE producer and the instruments do not directly address the volume risk they face.

Capability-based Contracts for Difference (CB-CfD)

As mentioned above, traditional CfD and CI-CfD are related to the volume of <u>injected</u> electricity. However, in case demand is met with cheaper sources of electricity or the generation is reduced as congestion management or another service to the market, this volume doesn't represent what the generator is <u>able to offer</u> to the market according to the wind speed. Therefore, TSOs suggest that capability, defined as the maximum <u>possible expected injection</u> for an ORE at a given time, could provide a better volume determination than injection. The volume of the CB-CfD is then not based on the actual transmitted electricity, but on the capable volume based on forecasts. The CB-CfD income is paid by the state as the counterparty of the CfD and equals the difference between market income and strike price times the expected injection (capability).

Figure 58: Capability based Contracts for Difference (CB-CfDs)



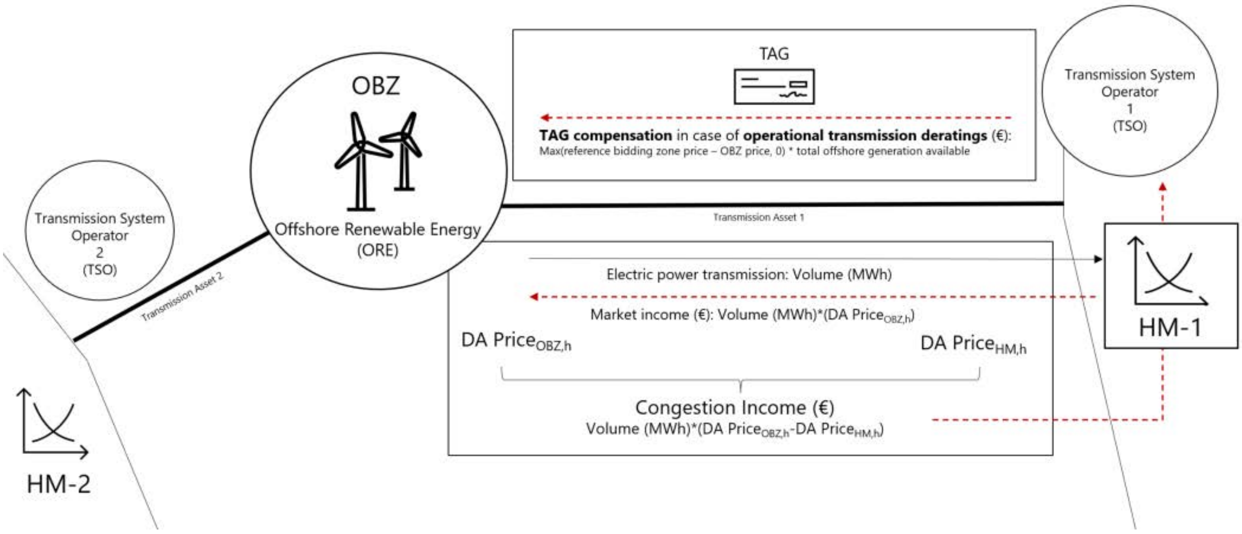
Source: Based on Elia (2022)

Transmission Access Guarantee (TAG)

The TAG is a compensation mechanism given by TSOs to ORE generators, in case the capacity needs to be reduced because of operational deratings (Laur et al., 2022). With the implementation of the TAG, the ORE generator receives the price spread between the reference price and the price at the bidding zone times the total generation available:

TAG compensation = Max (reference bidding zone price – OBZ price, 0) x total offshore generation available. Figure *59* describes the mechanism.

Figure 59: Transmission Access Guarantee (TAG)



Source: Based on European Commission (2022)

3.4.3 Issues of risk hedging measures

By suggesting the redistribution of CI to compensate for the risks of OREs, two important issues arise: the possibility of cross-subsidization and discrimination against other technologies.

While the CI is supposed to compensate for the risk of investment in the OBZ, this should not finance support for offshore generators in hybrid projects. In the case of the CI-FTR and CI-CfDs, one of the identified problems is the possibility of an overcompensation (cross-subsidization) of the OREs, since the ORE not only gets compensated in case of operational deratings, but whenever the price of the onshore bidding zone is higher than the OBZ price. This is not the case for the TAG, since it only applied to the case of operational deratings and therefore does not create any overcompensations. Furthermore, by shifting CI from TSOs to ORE generators, revenue adequacy of regional TSOs might be compromised (Laur et al., 2022).

Furthermore, critics point out that the redistribution of CI applied to OREs are discriminatory against other technologies, since they only apply to offshore renewable energy.

3.4.4 Ongoing debate at the EU level

Since the concept of congestion income redistribution is not part of the current EU legal framework and the implications of implementing OBZs are just starting to be fully grasped by stakeholders, all the above mentioned instruments (CI-FTR, CI-CfD, CB-CfD and TAG) would require some kind of regulatory reform. Notably, TAG was considered as part of the ongoing electricity market reform and has been since then debated in the negotiation processes between the EU Commission and the EU Parliament.

In the most recent draft proposal, it is suggested that PPAs, two-way CfDs and similar instruments are used to mitigate risks faced by ORE generators operating in OBZs. In the draft, it is clarified that TSOs shall aways guarantee ORE generators access to the transmission capacity of the hybrid interconnector and in case this transmission capacity is restricted, the TSO will compensate the generator by an amount equal to the additional congestion income earned by the TSO.

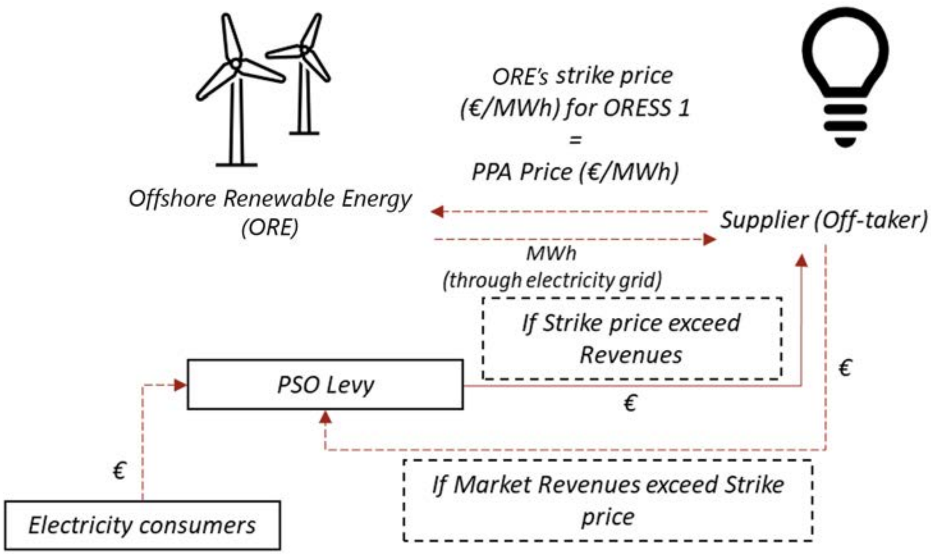
In turn, the compensation received by the ORE generator shall be limited to the production capability available to the market, and not a projection thereof. Before the end of 2024, the CACM GL Regulation (EU 2015/1222) will be modified accordingly to reflect these provisions and specific calculation methods will be outlined.

3.4.5 Solutions and instruments

Considering the issues identified and the ongoing debate at the EU level, there are three solutions on how to design de-risking measures, which could accompany the introduction of OBZs. These are not mutually exclusive alternatives but instead a menu of options that can be utilized:

- **EU de-risking instruments**: as mentioned, the specific choice of instruments depends to a considerable extent on the result of the ongoing on ORE policy and regulation at the EU level. Taking this into consideration, it is apparent that PPAs, CfDs and a partial compensation mechanism similar to the TAG may be used. Similarly, FTRs are also well-known instruments which are part of the existing regulatory framework. In principle, these could be pre-allocated (preferably not for free) at the ORE tendering stage. It is important to note that not all these instruments address the same kind of risk. For example, FTRs, PPAs and CfDs are price hedging instruments, while the TAG is a volume risk mitigation instrument.
- **State aid mechanisms**: re-assessing the existing state aid mechanism designed for Phase 1 and adapting it to the forthcoming phases in the transition to the plan-led regime, which – as recommended – could include the adoption of OBZs. With its two-way feed-in-premium, Ireland has created an instrument that effectively decouples the ORE developer's revenue from the electricity market price in the OBZ. This design (Figure *60*) which combines a PPA agreement with a double-sided CfD has positive features that can be extended.

Figure 60: Two-way Feed-in-Premium



Source: Authors

Figure 60, the two-way Feed-in-Premium is a construction in which the ORE generator enters into a PPA with a supplier, who acts as off-taker. It is the supplier which enters an agreement with the PSO levy, according to which this receives payments if the strike price exceeds revenues and in the opposite case, the supplier pays back to the PSO levy.

- **Access Rules:** the access rules or set of market rules define the obligations of an interconnector relative to the existing market mechanism, as well as obligations and duties between the transmission asset operator and the ORE generator. These documents, which usually cover force majeure and emergency situations as well as line outages due to maintenance could further accommodate conditions to mitigate the risk perceived by ORE generators.

3.5 What cost recovery model for Ireland? – Recommendations

Rather than recommending one single and specific cost recovery model for hybrid projects in Ireland, this section outlines a series of recommendations that can contribute to the overall achievement of Ireland's overarching ORE policy development goals both effectively and efficiently. Namely, in a manner that increases the amount of ORE produced in Ireland in a cost-effective way, thus delivering overall socio-economic benefits.

The following recommendations must be read in consideration of the overall policy recommendations for a hybrid interconnection policy outlined in section 2.5.

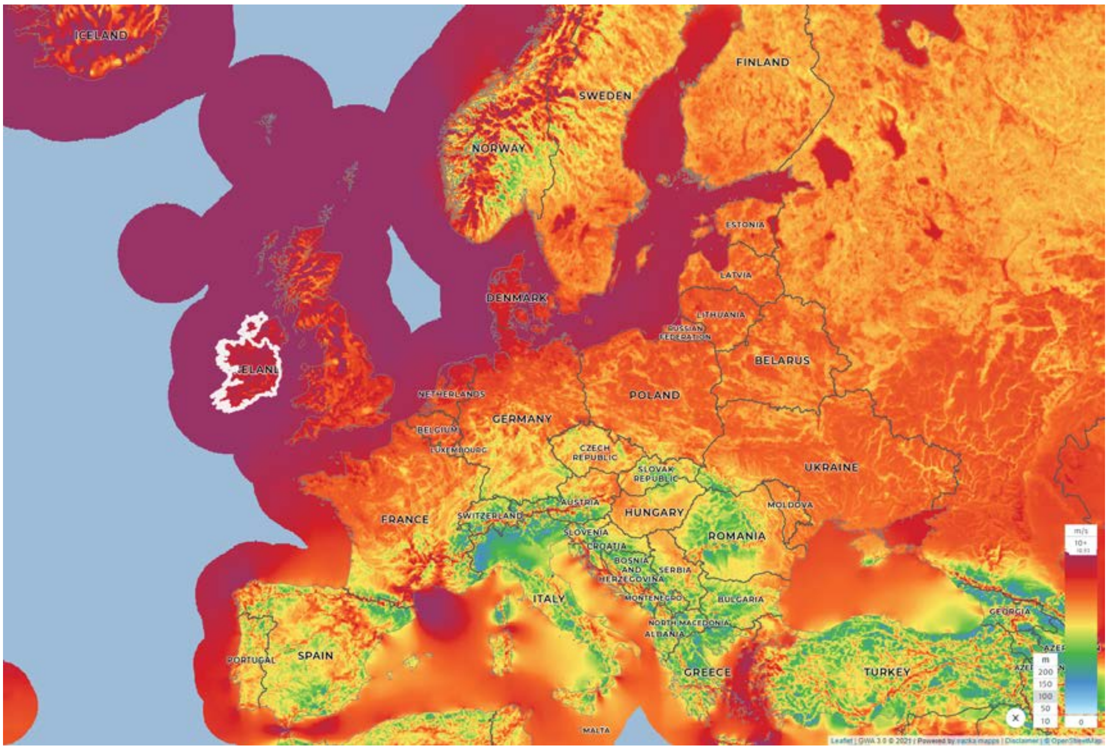
3.5.1 Recommendation 1: promote ORE development in commercial terms – as much as possible

With average wind speeds of approximately 10m/s @100m height, Ireland possesses top quality offshore wind resources, as Figure 61 indicates. In fact, Ireland ranks as one of the countries with the highest average wind speeds in Europe. This fact, together with the declining trend in offshore wind energy costs – a clear sign of increasing technological maturity – call for a policy approach that supports ORE development in commercial terms. Ireland's seabed provides clearly advantageous resources, which are very attractive for developers and should therefore compensate the state for having the right to utilize these. Rather than making taxpayers underwrite state aid, there should be a clear policy objective to reduce subsidies and increase the efficiency of the sector in the medium term (10 years).

With the given conditions, not only is Ireland's ambition to become a net energy exporter feasible, but it is also in the society's best interest – taxpayers and electricity consumers alike – that ORE development provides tangible gains. In addition to Ireland's ambitious decarbonization and overall environmental goals, ORE can help establishing a strong industrial sector and providing exporting revenue streams.

It is recommended therefore that ORE development happens, to the largest possible extent, on commercial terms.

Figure 61: Offshore wind speeds in Europe



Source: DTU (2023)

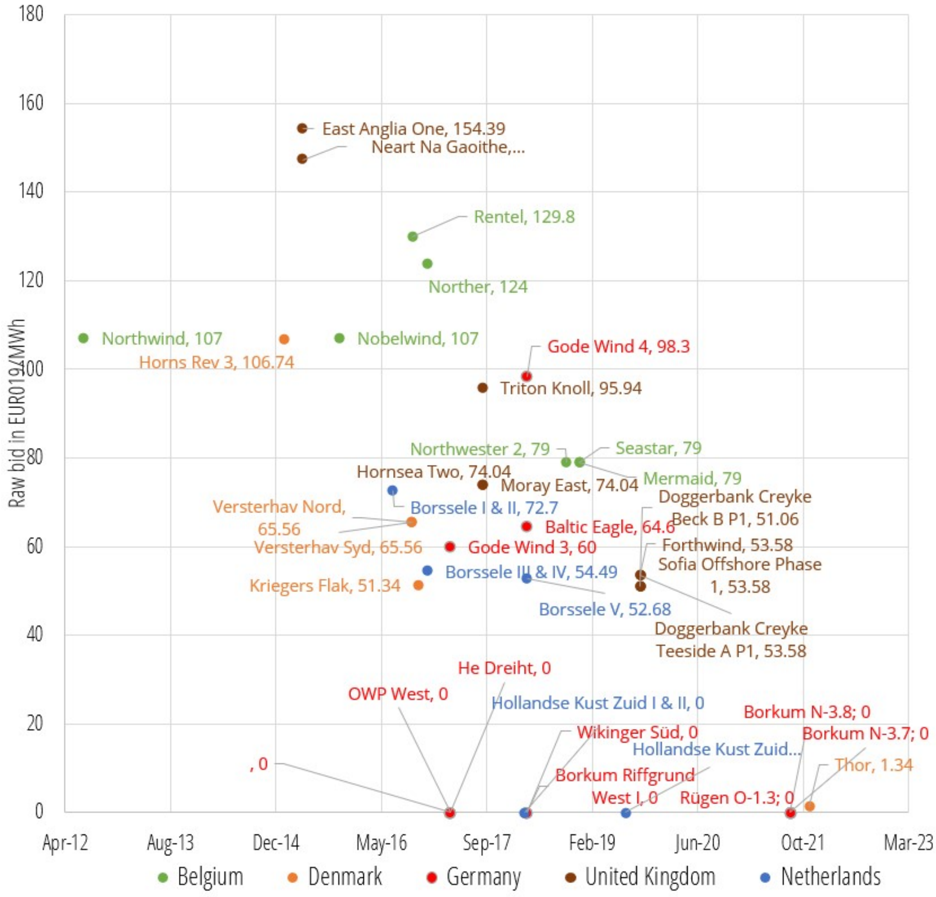
Recommendation 1A: revise the auction design for the fortchoming phases in the transition to the Plan-led regime and aim at increasing efficiency

One desirable property of well-designed auctions is their ability to deliver efficient outcomes. In the context of offshore wind auctions, this means that producers with the lowest cost obtain the right to produce and obtain state aid. In recent years, offshore wind auctions have shown a declining trend in the level of state aid required with a few projects (such as the Hollandse Kust Zuid Wind Farm Zone Sites I and II) being granted with zero subsidies.

Although auction designs are not generally comparable due to differences in design features, Jansen et al. (2020) harmonized offshore wind auction results from Europe and concluded that offshore wind power generation can be considered commercially competitive in mature markets. Between 2015 and 2019, the price paid for power from offshore wind farms across northern Europe fell by 11,9% per year and bids received in 2019 translate to an average price of 51 EUR/MWh. Enerdata (2022) updated the data gathered by Jansen et al. (2020) and included auctions taking place as early as October 2021 (Figure *62*). A comparison between the average price of Ireland's Phase 1 auction (86,05 EUR/MWh) with the data points on the figure, indicates that Ireland's support payments have the potential to become significantly lower.

An ex-post analysis of Phase 1 auction results could help identify factors that played a role in the participants' bidding behaviour and – more importantly – could help re-design the auction mechanism and re-consider policy decisions to induce efficiency in the forthcoming phases of the transition to the plan-led regime. Although it is outside the scope of the present report, it is possible to hypothesize that a combination of risk considerations and supply chain constraints could have influenced the result, which is above the average support received.

Figure 62: Historical auction results (EUR/MWh) over the 2012-2021 period for northern Europe



Source: Enerdata (2022)

Recommendation 1B: make state revenue maximization and non-financial considerations an important element of the ORE policy

Another possible objective of practical auction design is revenue maximization - when an auctioneer sells goods or services, it aims at collecting the maximum possible revenue. Ireland, as owner of vast maritime resources (Irish landmass only makes up 10% of Ireland's territory) has both the right and the duty to maximize their societal benefit. One possible way of achieving this is through a concession-based mechanism in which the state grants ORE developers the right to use the seabed throughout the lifetime of an ORE generation project, based on revenue maximizing auctions. The Crown Estate's experience could be relevant in this respect.

Furthermore, non-financial considerations can also be incorporated to the ORE policy, including auction mechanisms. In ORE policy development, there exist a series of non-financial aspects which, by their nature, cannot be measured by a price or a financial bid. For example, the impact of ORE development on the environment and communities, as well as the decommissioning approach of ORE generation facilities are all relevant aspects that a holistic ORE policy development may value and incorporate. With regards to this, the Dutch experience in ORE auction design could prove relevant.

3.5.2 Recommendation 2: be open to the cap and floor regime for Ireland's part of a hybrid interconnector project

Earlier in this report (see section 2.5), it was suggested that Ireland should have openness to the cap and floor regime, as this approach would avoid committing to fully underwriting investments on behalf of Irish consumers. It was also recognised that this model, which is already known and applied in Ireland, provides a combination of regulatory certainty and exposure to a market-based stream of revenues.

Based on the analysis of this chapter (see section 3.3), the main argument to add is *regime compatibility*. Ireland's Policy Statement on Electricity Interconnection (July 2023) contains, inter alia, a commitment to developing a potentially hybrid interconnector with the GB market beyond 2030. Taking this into consideration, openness to the Cap and Floor regime by Ireland – which will presumably be the enduring regime for the development of OHAs in the GB market – would greatly facilitate aligning incentives and reaching a common understanding in relation to the revenue and cost sharing agreements.

Recommendation 2A: assess existing tariff frameworks to advance ORE development and develop initiatives that support Ireland's energy transition

One defining element in Ireland's transition to the plan-led regime is network usage. Network capacity, which is an inherently scarce resource, guides location decisions. For example, in Ireland's Policy Statement on the Framework for Phase Two Offshore Wind (March 2023), it was determined that the location of ORE Designated Areas for Phase Two will be geographically aligned with available onshore grid capacity.

Considering the relevance of network capacity, it is relevant to recall that tariffs serve the double role of recovering costs and guiding network usage decisions, as these send price signals to grid users.

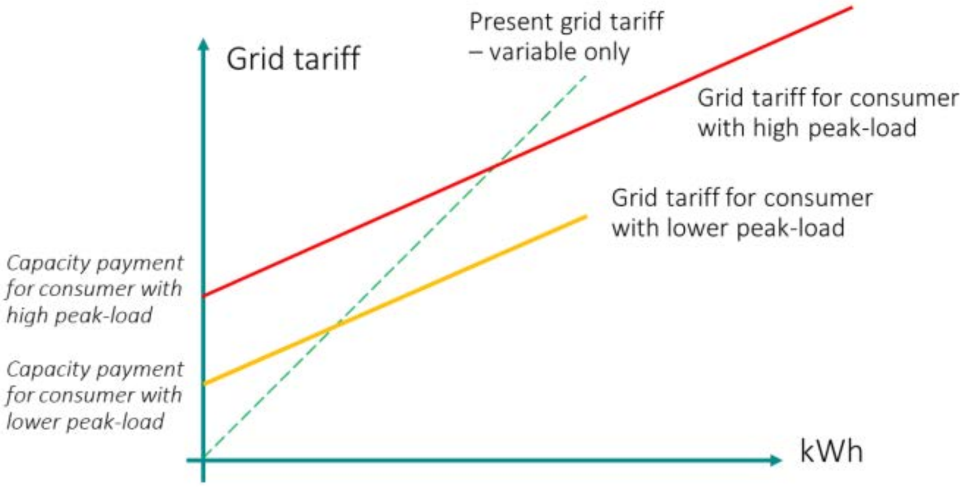
Recommended initiative 1: assess if existing tariffs incentivize efficient network usage

Today, EirGrid already implement a Demand Network Capacity Charge (EUR/MW), Demand Network Transfer Charge (EUR/MWh), and a time-differentiated Demand System Services Charge, which provides time differentiated signals that reward flexible consumption. At the producer's side, EirGrid implement a set of Transmission Use of System Charges (TUoS), including a Generation Network Location-Based Capacity Charge, which provides locational signals.

This tariff structure matches existing best practices in countries such as Denmark, where the Danish TSO Energinet is implementing a geographically differentiated producer payment, aimed at recovering connection costs through a fixed substation connection contribution, a geographically differentiated standard connection contribution based on capacity (per MW) in addition to a location-dependent feed-in charge per unit of energy (MWh).

At the demand side (see Figure 63), Energinet is also moving away from a simple energy payment (DKK/MWh) to a more cost reflective system, which reflects grid capacity usage in addition to energy transport. To this end, the Danish TSO is introducing a fixed yearly capacity payment (DKK/MW/year) and correspondingly reducing the energy (DKK/MWh) payment. This energy component will be subject to time differentiation, such that a higher energy tariff payment is charged on grid users at times of high and peak load.

Figure 63: Energinet's proposed grid tariff reform.



Source: Energinet (2022).

Based on these observations, it is recommended that EirGrid assesses the impact of its tariff design on an ongoing basis such that:

- On the producers' side, it is ensured that developers locate production in sites that cause the least congestion to the grid
- On the consumers' side, it is ensured that flexible consumption is following price signals, leading more users to shift their consumption to off-peak hours

Recommended initiative 2: develop a dedicated tariff framework for ORE development

Although EirGrid's tariff framework lives up to best practices, it still has not developed a dedicated tariff framework for ORE. It is therefore recommended that it develops a dedicated framework for ORE development that aligns with the chosen cost recovery mechanism for hybrid projects and the overall offshore grid infrastructure. As part of Ireland's transition to a plan-led regime, EirGrid's role is changing significantly as its offshore asset base is expected to be in the order of 5 billion EUR by 2030 – effectively evolving from an "asset light" business model into one in which a higher degree of financial (and other) requirements will need to be met (CRU, 2023).

Ireland could consider Denmark's and GB's suggested models (respectively discussed under 3.2.1 and 3.2.2) as inspiration, but it must be emphasized that Ireland's future ORE tariff framework should be in line with its own energy policy objectives. Not least, this framework should be aligned with I-SEM's and the EU's regulatory framework. For example, any change to the tariff framework should be harmonized and approved by the regulatory authorities of both Ireland and Northern Ireland and if this change entails producer payments, these should be in the 0-0,5 EUR/MWh range in accordance EU Regulation (838/2010) on inter-transmission system operator compensation mechanism and transmission charging.

This ORE tariff framework should:

- Not distort developers' incentives to invest in ORE generation
- Incentivise private investors (if these are involved) or EirGrid to build the hybrid transmission infrastructure required for ORE development and to adequately recover their investments

- Split the transmission infrastructure cost between different stakeholders in a just and cost reflective way

Recommended initiative 3: develop incentives to optimally integrate Power-to-X into the Irish grid

Considering the emergent role of green fuels (especially green hydrogen) in Ireland's renewable development ambitions, initiatives that can contribute to ensuring better utilisation of the Irish electricity grid and reducing the need for grid investments will be highly valuable. In this respect, it is worth mentioning three relevant Danish initiatives which could be inspirational to the Irish energy sector. The Danish political agreement on a national Power-to-X strategy triggered the following initiatives aiming to ensuring better utilisation of the electricity grid and therefore reducing the need for grid investments.

- Implementation of **direct lines** to facilitate the co-location of generation and consumption, hence reducing the need for using the public transmission grid. The concept is expected to be used by new Power-to-X projects and in connection with onshore routing of new offshore wind farms, making it possible to establish more offshore wind power capacity with reduced burden on the public transmission grid.
- With the new method for **geographically differentiated producer payment**, Energinet aims to send a price signal to incentivize both locating new generation units closer to existing demand and locating new demand closer to existing generation.
- Implementation of **local collective tariffing,** which is based on the principle that consumers and producers within a local area can share the costs and benefits of grid usage, leading to an overall reduced payment for grid usage.

3.5.3 Recommendation 3: adopt a decision on the introduction of OBZs as part of the transition to the plan-led regime

In section 2.5 of this report, it was argued that to allow for a gradual emergence of hybrid interconnections, a proactive decision on the introduction of OBZs should be adopted. There is consensus among the different stakeholders involved that this approach is the most efficient and the one that would interfere less with existing EU regulatory principles (see section 1.1). To see this point, it is always useful to remember that the only operational hybrid project in the world (the KFCGS) received a derogation from existing EU regulation to be able to operate. It was also mentioned that the review of the bidding zone configuration may interact with Ireland's existing Designated Maritime Area Planning (DMAP) process, which determines the broad area where ORE projects can be developed.

The review on specific cost recovery models proposed in Denmark and the UK (section 3.3) has reinforced this recommendation. The main lesson obtained is that the cost recovery mechanism for hybrid interconnectors is understood as a joint package of decisions, in which the transmission asset's revenue and cost framework is designed in parallel to the market design environment and both decisions are taken simultaneously.

Recommendation 3A: establish a possible pathway for sequential build-up, which opens up to "hybridization" and re-negotiation of the regulatory framework with ORE generators

It has been recognized that hybrid projects can be complex due to the technical requirements and the need to establish political, technical, and regulatory cooperation between different institutions.

The only operating hybrid interconnector (the KFCGS) and Denmark's planned energy islands are examples of projects that are "hybrid by design" or "hybrid from the outset", as ORE generation, connection to shore and cross-border transmission assets are simultaneously planned at the beginning of the process.

However, an alternative pathway allows for "hybridization". ORE generation may be first established and radially connected to be later expanded to become a hybrid interconnection. Such is the case of Norway's Southern

North Sea II (Sørlige Nordsjø II) project, in which the initial phase of the project (1,5 GW) will be developed as a radial connection with a possibility of expanding into a hybrid interconnection in the second phase (1,5 GW).[39]

Within this modular development framework, both the UK and the Netherlands plan hybrid interconnections and ORE generation as two separate processes, which may nonetheless result in a hybrid connection to adjacent bidding zones. In the UK, it is expected that ORE developers will interact and coordinate with interconnector developers for the establishment of a OHAs, but if the process does not lead to a hybrid project, this can proceed as a regular, point-to-point interconnector. As mentioned in the best practices analyses (section 1.3), the Netherlands has established a standardized procedure to allow for anticipatory investments to account for the possibility of hybridization.

To account for the possibility of hybridization in Ireland, it was recommended in section 2.5 that Ireland announces a policy commitment to connect all ORE generators radially under a HM solution before 2030 (or the 5 GW target is reached) and to announce the establishment of an OBZ afterwards to facilitate hybridization. It was also recommended to identify a suitable de-risking measure to allow ORE developers hedge the increased volume and price risk present due to the establishment of OBZs.

In addition, it is recommended in the present section to initiate a dialogue with industry stakeholders to understand the conditions that would have to be met for a possible change in the market design and to consider the establishment of a compensation for a possible change in regulatory setup. Such compensation mechanism would be an addition relative to the de-risking measure described before.

[39] Norwegian authorities finally decided that the first phase of the project would not contain on hybrid interconnections, although they initially considered this possibility. Part of the assessment is contained in a report prepared by NVE (2023) the Norwegian NRA.

CONCLUSIONS

Ireland has both the ambition and the quality of ORE resources to become an important energy producer and net exporter. Beyond its environmental targets, the country is pursuing a strategy to transform its economy such that emissions decouple from economic growth.

However, as it presently stands, the country has a dramatically higher ambition than both its currently installed ORE generation (25 MW) and transmission capacity (500 MW). To put these figures into perspective, the expressed goal of reaching 7 GW ORE by 2030 amounts to an increase of approximately 280% and the expected transmission capacity buildout correspond to a tenfold increase by 2033 (if total transmission capacity reaches 5000 MW by then). To be fair, many of the changes are underway, as the ORESS Phase 1 resulted in the allocation of state aid to build 3 GW ORE capacity and if Greenlink (500 MW) and Celtic are included, transmission capacity will be around 1700 MW by 2026.

With this kind of ambition, only a comprehensive policy and regulatory overhaul can secure that Ireland's resources develop. In this respect, the transition to a plan-led regime is a step in the right direction, so long as the specific policy decisions are designed correctly and are implemented promptly.

In what concerns hybrid interconnector policy development, it is important that Ireland identifies the role that such type of infrastructure will play in the achievement of its ambitions. On the one hand, hybrid projects are one type of interconnector that can support Ireland's overall interconnection target. On the other hand, hybrids can potentially enhance renewable integration through the effective utilization of the same piece of infrastructure for two different purposes.

However, as has been mentioned in this report, these projects can be both complex and costly, and their development should not be considered an objective in itself – unless there is clear evidence that they contribute to the achievement of Ireland's energy policy goals.

To facilitate the emergence of hybrid interconnector projects in Ireland, this report has argued for:

- Implementing an **offshore transmission strategy** that includes a **holistic offshore-onshore design approach which**, inter alia, includes cost/benefit scenarios and analyses of hybrid interconnection viability in cooperation with potential partner countries, and that determines and quantifies the required onshore network reinforcements and other interactions resulting from developing the offshore network.
- Opening the possibility to plan and execute **anticipatory investments in the transmission network**, which allow for future "hybridization", if evidence in favour of hybrid interconnections is clear.
- **Proactively establishing** political and technical **cooperation** between Ireland and potential partner countries, at the political, technical, and regulatory levels.
- Having **openness towards the cap and floor model** for the financing of transmission assets, not only because this provides a framework that balances regulatory certainty with the incentive to operate the transmission asset efficiently, but also – with a pragmatic perspective in mind – to facilitate regime compatibility with the UK.
- **Planning for the introduction of OBZs**, such that: a) before 2030 or before Phase 2 is complete, radial connections under the Home Market design is the applied model, and b) after 2030 or the 5 GW target is reached, establish OBZs accompanied by suitable, non-distorting de-risking measures such as CfDs and PPAs

Following an analysis of existing proposals on cost recovery mechanisms, a few supplementary recommendations were also made:

- **Promoting ORE development in commercial terms**, as much as possible, and along this line revising the ORE auction design to increase efficiency. It was also recommended that revenue maximization and non-financial considerations become part of the ORE development policy.
- **Revising EirGrid's tariff framework** to account for ORE development and other issues such as the development of incentives for green hydrogen production.
- **Establishing a pathway for hybridization**, which includes possible compensation granted to developers who experience a change in the market design environment they operate.

RECOMMENDATIONS FOR FURTHER WORK

As with any comprehensive piece of work, there remain questions that cannot be answered in full detail. In what follows, a few recommendations for further work are presented:

1. Regarding energy modelling to substantiate offshore transmission planning and to support bilateral talks with potential partner countries:

- **Developing a model of Ireland's electricity system in an EU context:** one fundamental first step to illustrate the socio-economic benefits of interconnectors in general and hybrid projects in particular is developing a model of Ireland's electricity system, which includes interconnections with relevant countries, such as Great Britain, Belgium, Netherlands, and other surrounding countries in Western Europe. Such model will provide relevant Irish stakeholders (DECC, EirGrid, CRU) with a tool to build relevant evidence base to substantiate decisions.
- **Defining a baseline scenario and several counterfactuals with pre-defined time horizons to conduct specific modelling exercises that allow quantification of net socio-economic benefits and distributional impacts:** defining a baseline scenario entails defining future generation, demand, and interconnector build-up for the whole modelled area in pre-defined time horizons. For instance, as part of the reference case, interconnectors may be modelled in parallel to radially connected generation which will support the quantification of socio-economic benefits as well as the distributional implications (producer surplus, consumer surplus, congestion rents). Several counterfactual configurations could include:
    - Hybrid projects operating in home markets and hybrid projects operating in offshore bidding zones.
    - Sequential build-up of generation sites and development of Power-to-X configurations, including electrolysis located onshore and offshore as well as other developments such as the activation of demand from data generation centres and the re-purposing of the natural gas infrastructure.

  The idea behind this recommendation for further work is to create a solid energy system modelling base for Ireland, and to conduct detailed analyses such as the ones reviewed in section 1.2 of the present report. These analyses should build up on Ireland's existing ambitions, outlined in its Climate Action Plan, the Hydrogen Strategy as well as the Industrial Strategy for Offshore Wind.

2. Regarding the regulatory framework and the cost recovery mechanism:

- **Conducting analyses to determine distributional impacts of different cost recovery mechanisms for the offshore electricity grid.** One implication of Ireland's transition to the plan-led regime is the substantial buildout of the offshore electricity grid, leading to a considerable growth in its regulated asset base (estimated in the order of 5 billion EUR) by 2030. An enduring cost recovery mechanism for its new role as asset owner of the offshore electricity grid will be required and with it a tariff framework for ORE development may be necessary (see Recommendation 2A). Considering these developments, it is recommended to investigate the interplay between financial aspects of the offshore grid buildout and energy systems modelling. Specifically, the study would investigate different cost recovery mechanisms under different assumptions on equity and borrowing costs in the framework of energy systems modelling. In this way, the impact of electricity prices, tariff modelling and financial assumptions could be jointly assessed.

3. Regarding the institutional and organizational arrangements to facilitate the transition to a plan-led regime and the emergence of hybrid projects:

- **Conducting analyses of institutional and organizational frameworks:** as has been noted earlier in this report, the transition to a plan-led regime as well as the planning of hybrid projects can be complex. This will require a considerable effort to streamline processes and to facilitate the interaction of the different entities involved, possibly requiring a re-organization and re-evaluation of roles within Ireland's institutional framework. A detailed analysis of the technical competences and the checks and balances between involved institutions may be necessary.

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APPENDIX 1: IRELAND AS A NET ELECTRICITY EXPORTING NATION

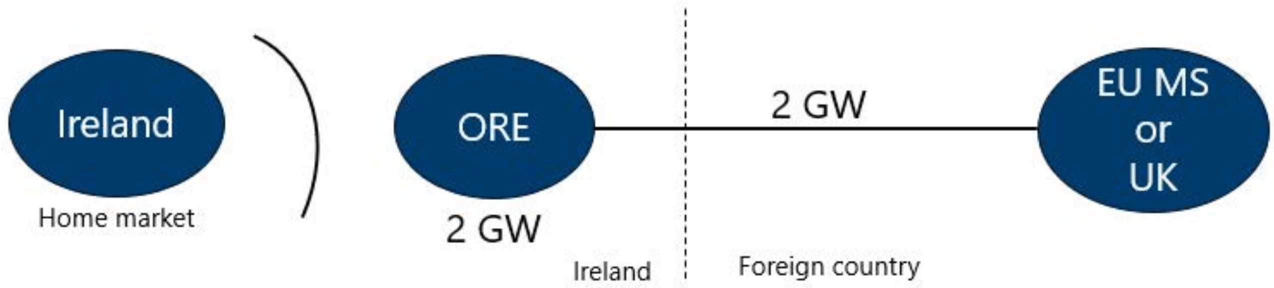
During the project, a question on the different market configurations for Irish ORE that would allow either establishing full export capacity or net export capacity was raised. To address the question, three hypothetical configurations for ORE were considered.

Configuration 1 – Full export capacity, HM design and no connection to the domestic market: Under this configuration, ORE generation (2 GW) is located on Irish waters but there is no transmission line to supply the Irish Single Electricity Market (I-SEM). However, there is a transmission line to a foreign country (2GW), which could be another EU Member State or the UK.

Under configuration 1, the price at which ORE production is compensated would presumably be the price at the foreign country. In this case the transmission line between the Irish ORE generator and the foreign country is internal and therefore its "Home Market" is the foreign country. For this project to be feasible, the value of the produced power would have to exceed the cost of the transmission line (Value of exported power > Cost of interconnection). It is assumed here that the cost of the transmission line is developed by the foreign country.

Under this configuration, the benefit to Irish society follows from the producer surplus of the Irish ORE producer, but ORE production on Irish waters provides no direct benefits to Irish consumers. An additional revenue stream that could results in benefits to Irish society would be through concession revenues obtained from the usage of the maritime space. One additional comment to this configuration is that, according to Ofgem's classification of OHAs, this corresponds to an NSI (Non-Standard Interconnector) as generation happens outside British waters.

It is assessed that this configuration is not completely realistic and overlooks other benefits that Ireland could obtain.

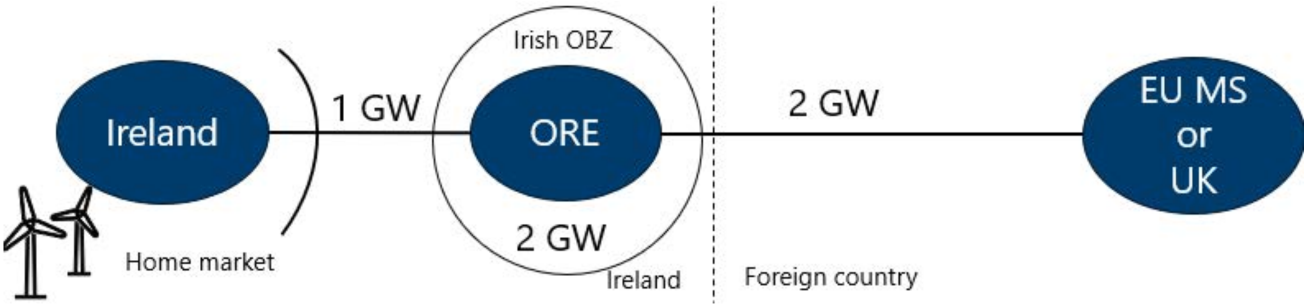


Configuration 2 – Net export capacity, OBZ design and connection to the domestic market: under this second configuration, ORE (2 GW) is located in an Irish OBZ and because it is expected that the flow will mostly be in the export direction, the transmission line between the Irish OBZ and the I-SEM (in this case noted as "Home Market") has lower capacity (1 GW) than the line between the Irish OBZ and the foreign country, which as 2 GW.

Under this configuration, the value of exports is given by the sum of producer surplus for both offshore and onshore generators, as producers onshore will also be able to export. In addition, the owner of the transmission asset also collects congestion rents. Assuming that the line between the Irish OBZ and the "Home Market" is owned and operated by EirGrid, it would collect congestion rents. The interconnection also adds value through increased security of supply when the flow is in the opposite direction, from the foreign country to Ireland. Under an outage situation, this line would alleviate deficit situations in the I-SEM.

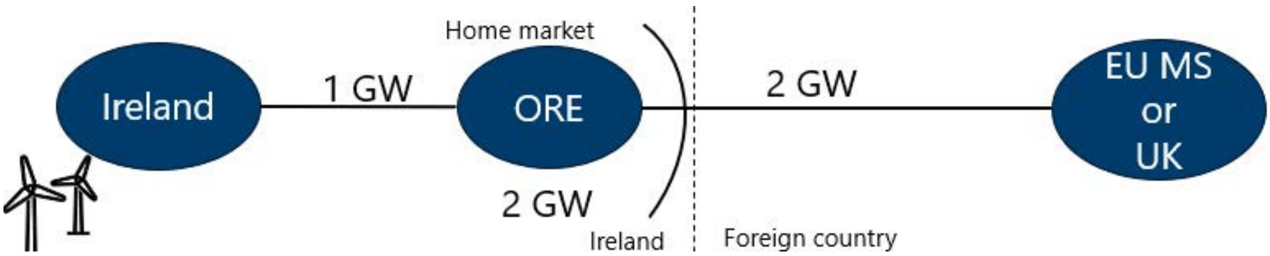
The total cost of the interconnection is to be shared between both transmission asset owners at both sides of the Irish border. For this hybrid project to be feasible, the sum of the value of the exported power plus the value of the interconnection must exceed the cost of the interconnector: Value of exported power + Value of the interconnection > Cost of interconnection.

As in configuration 1, this is also a NSI according to Ofgem.



Configuration 3 – Net export capacity, HM design and connection to the domestic market: this configuration is a variation of configuration 2. With the exact same capacities, the only difference is that the ORE generator is part of a Home Market, and the ORE producer therefore is compensated with the price at the I-SEM. The physics are the same, as the interconnector is also hybrid, but the market configuration is not. From a regulatory perspective, it would be difficult to comply with the 70% rule as either such a capacity is given to the market, or the ORE generator is curtailed.

The value of exports is as in case 2 and the feasibility considerations are the same. The market, however, is different.



APPENDIX 2: WORKSHOP REPORTS

Workshop 2

Workshop 2 consisted of two online meetings:

1) With industry stakeholders on 15/05/2023
2) With state bodies on 30/05/2023

Each meeting included two sessions covering:

- Session 1 on Policy Options to incentivize hybrid interconnections in Ireland
- Session 2 on ORE co-existence and co-location in Ireland

The main insights from the session on hybrid interconnection policy are outlined below.

Session 1: Policy Options to Incentivize Hybrid Interconnections in Ireland

The main objective of the session was to explain the current state of the analysis under D3, including specific policy recommendations and to obtain feedback from stakeholders.

The session began by introducing the reasoning behind hybrid projects in Ireland, together with the success criteria for Ireland's hybrid interconnection policy. Afterwards, the session moved on to presenting the main policy recommendations for an Irish policy statement on hybrid interconnectors, which were summarized in a "Policy Options paper".

The following feedback points summarize the main inputs received:

1. Unbundling regulations will have to adapt for private participants to develop hybrid projects

It was observed by one of the industry representatives that – from a private investor perspective – proving the unbundling requirement to regulatory authorities is a challenging process already. The unbundling principle states that generation and transmission asset owners must not be owned by the same entity.

However, in this specific context, unbundling refers to the requirement that a private investor must prove to regulatory authorities that it lives up to the unbundling requirements. From the private investor perspective, the scope of application of the unbundling requirement may have to be re-assessed in the future because private investors operating in the energy sector tend to own both transmission and generation assets as part of their portfolio. In the industry representative's view, the scope of application should be limited to generation assets using the transmission asset specifically. Allowing private investors behind a hybrid interconnectors owning offshore wind generation is likely to take a long time.

2. Recommended holistic plannning framework is viewed positively

A common point of agreement among participants was that a holistic approach to planning in which both onshore and offshore grid considerations are incorporated will be beneficial. Being able to have answers to the question on "where to connect" and "when to connect" will clearly facilitate the process. Along the same line of discussion, anticipatory investments are viewed as beneficial insofar as they increase certainty with respect to both the connection date and the place for available connections onshore.

3. Multi-region loose volume coupling between UK and the EU market is sub-optimal

The EU internal market for electricity operates under the Single Day-Ahead Market Coupling (SDAC) Mechanism in which cross-border capacity between bidding zones is known before exchange prices are calculated. In contrast, after Brexit, cross-border trade between the GB market and EU bidding zones has been calculated separately with one auction for transmission capacity and another one for energy. As a solution the problem, the Trade and Cooperation Agreement between the EU and the UK have proposed to implement "multi-region loose volume" coupling which, determines cross-border flows and prices only in a subsequent step leading to sub-optimal results relative to SDAC.

Taking this into account, one workshop attendee encourages the Irish government to work with the UK to find a solution that allows both countries to participate in full market coupling again.

4: Introduction of offshore bidding zones should also account for Designated Maritime Area Plans (DMAP) process

As part of the policy recommendation to introduce offshore bidding zones as part of the transition to a planled regime, one industry representative mentioned that it would be relevant to consider this as part of the ongoing introduction of the Designated Maritime Area Plans (DMAPs).

Workshop 3

Workshop 3 comprised of two online meetings:

1) A meeting with state bodies on 29/06/2023

2) A meeting with industry stakeholders on 30/05/2023

Each meeting included the following sessions

• Session 1: Policy Options to incentivize hybrid interconnections in Ireland

• Session 2: ORE co-existence and co-location in Ireland

The main insights from the session on hybrid interconnection policy are outlined below.

Session 1: Cost Recovery Models for Hybrid Interconnections

The main purpose of the session was to discuss and present existing cost recovery mechanisms for hybrid projects as well as de-risking measures for commercial parties participating in a hybrid project. The session introduced specific cost recovery models under consideration in two relevant jurisdictions, namely the UK and Denmark and then discussed potential barriers and mechanisms to ensure regime compatibility in projects in which transmission asset owners are regulated according to different models. As part of the session, the main aspects on the ongoing EU debate on de-risking measures for offshore wind developers were presented. The session finalized with the presentation of several recommendations for the design of cost recovery mechanisms for hybrid projects in Ireland.

The following feedback points summarize the main inputs received:

Viewing offshore wind development in Ireland in commercial terms was positively received

One of the recommendations put forward was to develop Ireland's offshore wind potential in commercial terms, which in more practical terms means to increase the efficiency of the auction to allocate state aid mechanism and to consider maximizing state revenue from the allocation of rights to develop offshore wind in Irish waters.

One of the stakeholders made the comment that, given the maturity of offshore wind technology, it would make sense to think of it in commercial terms. However, it remains to be clarified if this would be under a merchant model or an optimized model for state aid.

Viewing Ireland as a net exporter rather than as a pure exporter of offshore wind energy was supported

During the session, three hypothetical configurations for Ireland as an offshore energy exporting country were presented. The configurations alternated on the introduction of offshore bidding zones and home market as well as on the extent to which Ireland would be interconnected with the Irish onshore bidding zone (the I-SEM). Stakeholders reacted to these and commented that a configuration in which both the value of energy exports and the value of interconnections (e.g., through added security of supply) should be prioritized.

Considering a sequential buildup of hybrid projects as a reasonable decision

During the session, another point of discussion related to the sequential build-up of a hybrid project, i.e., whether a project that is initially connected radially could progressively become hybridized. While this idea was welcomed, it was also highlighted by one of the participants that many early decisions would have to be made to make this happen. Significant early commitment decisions would need to be made to make this a reality. One potential barrier for this would be opening to re-negotiating the terms of projects which are initially connected radially and then progress to a hybrid configuration.

Thank You

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