

D7.4 Economic framework for a meshed offshore grid

PROMOTioN – Progress on Meshed HVDC Offshore Transmission Networks
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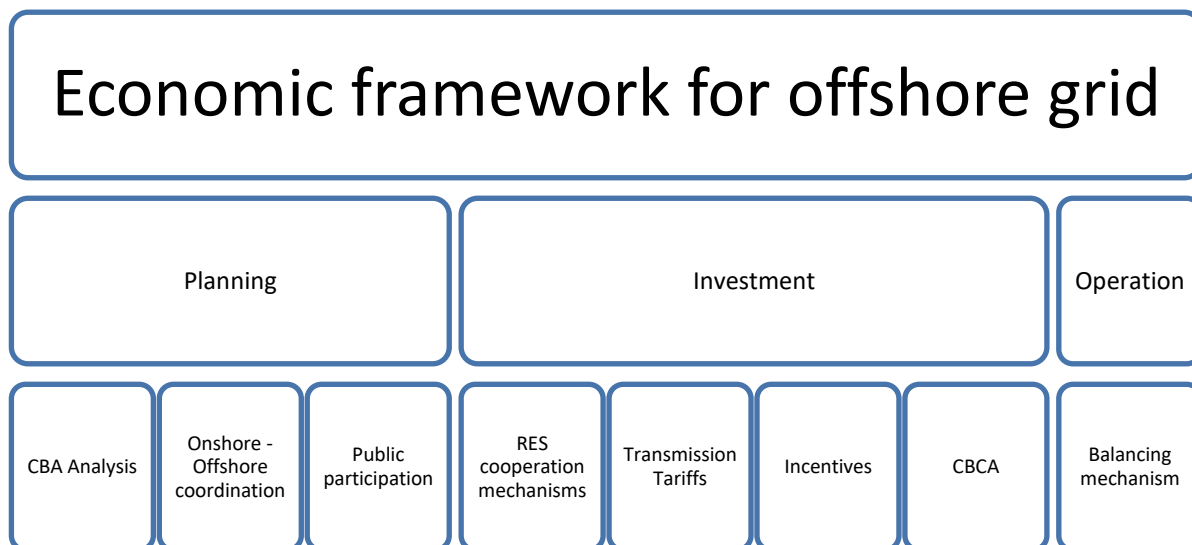
EXECUTIVE SUMMARY

INTRODUCTION

Work Package 7 (WP7) of the Progress on Meshed HVDC Offshore Transmission Networks (PROMOTioN) Horizon 2020 project focuses on various legal, financial and economic aspects of developing an integrated offshore infrastructure.

Task 7.2 focuses on the development of an economic framework for the offshore grid in terms of three building blocks, namely: planning, investment, and operation.

1. **Offshore grid planning** comprises three topics, namely: Cost-Benefit Analysis (CBA) methods, onshore-offshore coordination, and public participation.
2. **Offshore grid investment** comprises four topics: cooperation mechanisms for renewable support, transmission tariffs, investment incentives, and Cross-Border Cost Allocation (CBCA) methods.
3. **Offshore grid operation** focuses on the balancing mechanism in the offshore wind context.



This final report extends our intermediate report with the addition of three new topics: incentives, CBCA and the balancing mechanism. The remaining chapters are identical to the intermediate report. In this section, we provide a **summary** of the research that has been undertaken so far and the main conclusions from our analysis.

OFFSHORE GRID PLANNING

CHAPTER 2: COST BENEFIT ANALYSIS FOR OFFSHORE ELECTRICITY GRID INFRASTRUCTURE

Cost-Benefit Analysis (CBA) is a well-established tool to guide investment decisions in various sectors, including the energy sector. The most well-known CBA methodologies in the EU energy context are the CBA methodologies for energy infrastructure published by ENTSO-E and ENTSOG. A harmonised system-wide CBA methodology is applied by the ENTSOs to provide objective information uniformly about the projects taken up in the Ten-Year Network Development Plans (TYNDPs).¹ In addition, the CBA methodology is relevant for: 1) Establishing a regional list of projects of common interest (PCIs). 2) Submission of investment requests by PCI promoters to National Regulatory Authorities (NRAs). 3) Decisions of NRAs on granting incentives to PCIs. 4) Providing evidence on significant positive externalities for the purpose of European Union financial assistance to PCIs. It should also be noted that results from the CBA are valuable in the process of making Cross-Border Cost Allocation (CBCA) decisions.

Currently, major offshore electricity infrastructure projects with a trans-national impact, both point-to-point interconnectors and combined solutions, are part of the PCI list. The projects which applied for the 2015 PCI list were assessed applying a CBA consistent with the ENTSO-E methodology approved by the European Commission. Earlier projects have been evaluated using ad hoc methods.

This chapter contains three objectives: 1) Present a framework for a robust CBA with a focus on offshore infrastructure. 2) Apply this framework to assess the ENTSO-E's CBA methodologies. 3) Apply this framework to assess three case studies of offshore transmission infrastructure projects (EWIC, COBRACable and ISLES).

More specifically, we apply the theoretical framework developed by Florence School of Regulation over the course of several years. This framework has gone through several iterations and has boiled down to a checklist consisting of 10 guiding principles. These principles are divided into concerns related to the input (consider project interactions, data gathering process, disaggregated reporting of cost data), the calculation (using common list of effects, disregarding distributional concerns, explicit algorithm for calculating the net benefit, common discount factor, dealing with uncertainty), and the output (disaggregated reporting of benefits, final assessment of the projects) of a CBA.

The assessment of the ENTSO-E CBA 1.0 and 2.0 methodology using the above-mentioned framework identified three key issues regarding 1) dealing with interactions between PCIs (coordination). 2) gaining trust and public acceptance (transparency). 3) deciding where the experts stop and the politics start in the valuation of PCIs (monetisation). The recommendations for addressing these issues are presented below:

¹ For the TYNDP 2018, the ENTSOs for gas and electricity have, for the first time, combined their efforts and expertise to develop scenarios to assist with decision making for future infrastructure investment needs.



Recommendation 1: *Dealing with interactions between (offshore) PCIs.*

To deal with the interactions between PCIs, we recommend additional improvements to the clustering of projects and the baseline definition in the common CBA method. We also recognise that individual project promoters might lack the information and resources to do this, which is why we suggest that this could become a task for the ENTSOs or Regional Groups instead of promoters.

This coordination issue is especially relevant for offshore infrastructure projects, as an offshore grid in the North Sea would be build up almost from scratch. This implies that the outcome of the CBA analysis of individual offshore energy infrastructure projects, serving as future links creating an offshore grid in the longer term, is expected to be highly interdependent.

Recommendation 2: *Gaining trust and public acceptance.*

To gain trust and public acceptance, we recommend harmonised and disaggregated cost and benefits reporting, noting that we still have a long way to go, and noting that this is not even enough because the ambition should be an open source CBA model rather than a common method.

Disaggregated cost reporting is of importance in the context of offshore grid infrastructure as the technology used for such projects is relatively immature, making it harder to estimate the exact costs. Also, in offshore projects the welfare of typically more than just two countries is significantly impacted by a project, making an agreement on cross-border cost allocation (CBCA) decisions harder.

Recommendation 3: *Reducing the politics in the valuation of PCIs*

To reduce the politics, we emphasise the importance of a full monetization of the value of PCIs and note that we could ask the Regional Groups to express their policy priorities at the start of the process via the eligibility criteria, which would also increase the transparency of the process.

Again, this concern is of vital importance in the offshore context as in addition to an increase of social-economic welfare, due to a more efficient dispatch in coupled markets, many externalities, such as the integration of renewables and an increase of security of supply, are expected to be significant.

CHAPTER 3: COORDINATING ONSHORE-OFFSHORE GRID PLANNING

The key to successful implementation of an integrated approach to offshore grid development in the North Sea is the coordination among various stakeholders. In this chapter, we study the interaction between onshore grid development, traditionally performed by TSOs, and the development of offshore grid infrastructure. We follow a case study approach to investigate how onshore-offshore coordination of grid development is carried out in a national context. We analyse onshore-offshore coordination in four countries, each representing a different approach. The selected states are Germany, Denmark, the UK, and Sweden. We identify the key onshore-offshore coordination issues that may impact the development of the required offshore transmission infrastructure and the necessary onshore reinforcement.



The three selected dimensions based on an extensive review of the literature are *locational requirements for renewable energy support*, *onshore grid access responsibility* and *grid connection charges*. For each dimension, three possible regulatory practices are identified.

Locational requirements for renewable energy support: In the context of planning offshore wind development, locational requirements for RES support can be described by the question “where can a wind developer site an offshore wind farm?”. While deciding upon a site for developing an offshore wind farm, one needs to take various constraints into consideration. Therefore, during planning, effective coordination of various agencies is required. Three possible regulatory practices are identified that allow a varying degree of freedom to the developer in selecting the location of a new offshore wind farm and concurrently avail the renewable energy support namely open door (developer selects the site for the wind project), zone (the authorities identify a zone for offshore wind development) and single-site (authorities identify sites for offshore wind development).

Onshore grid access responsibility: Providing an offshore wind farm with the access to offer the power that it generates to the load centres as efficiently and as effectively as possible is an important dimension for the success of any such project. Three strategies for onshore grid access responsibility are identified: TSO-led (the transmission system operator is mandated by the concerned authority to be responsible for connecting the offshore wind farm to the onshore grid). Developer-led (the offshore wind farm developer is solely responsible for connecting the wind farm to the onshore grid). Third-party-led (the grid access responsibility lies neither with the incumbent TSO nor with the wind farm developer but with a third party).

Grid connection costs: Grid infrastructure cost incurred by the OWF developer would have an impact on its decision to invest in a project and on the incentive to connect the wind farms on shore at a connection point with minimal incremental cost for the network. From a system perspective, it is critical to have the right coordination between the actor responsible for grid access and the one responsible for paying the grid connection costs. Three strategies are identified for allocating grid costs – super-shallow (OWF developer is responsible only for the cost incurred for developing the internal network within its wind farm), shallow (OWF developer is responsible for the cost incurred in developing the internal network within the wind farm and the cost of connection up to the onshore connection point) and deep (OWF developer is responsible for the entire grid connection cost).

Within each case study, we first present a brief overview of the offshore wind generation development in the country under consideration. The overview is followed by a description of the historical development of the relevant regulatory options that have been utilised by the member state for offshore wind development.

The evolution of the analysed regulation in the four countries shows that the approaches varied not only between the countries but also over time; In Germany, for instance, the planning of offshore cables is now prioritised over the allocation of renewable support to wind farms, and not vice-versa as before. Denmark has consistently applied a single-site TSO-led scheme and introduced a tailor-made regulation for near-shore wind farms. Sweden seems to have remained stable regarding the assessed dimensions of offshore regulation. However, the Swedish energy



agency has proposed an overhaul of the system, which is currently being discussed. The UK has implemented a unique approach in which fully unbundled independent third-party builds (optionally), own and operate the offshore connection. However, the UK too is moving towards a more coordinated planning approach (open-door to designated zones).

CHAPTER 4: PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

One of the most critical aspects of the successful development of the offshore infrastructure, be it the wind farm itself or the related grid infrastructure, is the participation and support of the local population. While public participation has several advantages, several concerns are presented as reasons for limiting the level of public involvement in the development of offshore wind infrastructure projects. In literature, differing opinions on whether the offshore wind is less problematic compared to onshore wind exist.

To appreciate the importance of public and local community involvement in the successful development of offshore wind projects, firstly, it is essential to understand what aspects influence the perception of offshore wind projects by these stakeholders. This topic has been studied in depth in literature, leading to the identification of key factors that impact public perception of the development of such projects. In this chapter, we discuss one such framework from the literature that consists of five influencing factors, namely: visual impact (studies have shown that even a minor visual impact has a strong negative public perception). Local context and attachment (a robust link is observed between the historical and social context and the public perception of the development of offshore wind projects). Disjuncture between the local and global (studies suggest there appears to be a disconnect between the understanding the risks and benefits of offshore wind development from a global perspective vis-a-vis a local perspective). Relationship with outsiders (It is observed in literature that local community groups and government projects face much less public opposition as compared to large multinational energy companies). Planning, and participation (studies suggest that faith in the “fairness” of the decision-making process and the people in charge of this process with regards to offshore wind development project has a substantial impact on the acceptability of the project). This framework appears to be relevant for developing an effective strategy for greater public participation.

Internationally, wind power is perceived positively. However, instances of public opposition to onshore wind, as well as offshore wind power projects, have been observed. An effective public participation program can have a positive impact in ensuring successful development and deployment of the offshore wind infrastructure in the coming years. Understanding levels of stakeholder participation can aid in enabling greater and more effective public participation. It would also aid in identifying the possible scope of improvement in the current strategies used for public engagement in offshore wind infrastructure development. The stakeholder ladder developed by Miles and Friedman in 2006 is a useful tool to understand public participation. The “ladder” has been created to present the degree or level of stakeholder involvement in the development of any project. The highest degree of engagement is the proactive or trusting level consisting of five steps: stakeholder control, delegated power, partnerships, collaboration, involvement. At this level, the stakeholders are made to participate in the decision-making process actively. The next lower level in the ladder is “Neutral” consisting of four steps namely, negotiation,



consultation, placation and explanation. The third and lowest level of the ladder is called the 'autocratic' level consisting of three steps namely informing, therapy and manipulating.

Two case studies are analysed in this chapter. The first is on public participation in the development of the Middlegrunden wind farm in Denmark. It can be considered one of the first examples of offshore wind energy projects with active public involvement. The facility is owned 50% by Dong Energy and 50% by the Middlegrunden wind turbine cooperative. The second case study is on the Triton Knoll offshore wind in the United Kingdom. During the planning of this wind farm project, several statutory and non-statutory consultation steps were carried out by the project developers. The case studies provide insight into how greater public participation in offshore wind infrastructure development can be attained.

OFFSHORE GRID INVESTMENT

CHAPTER 5: COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

Effective renewable support mechanisms are an essential ingredient for ensuring the robust development of a decarbonized electrical system in Europe. Member states have implemented diverse types of renewable support mechanisms for incentivizing investment in, and production of electricity from renewable energy sources. Over the years these mechanisms have evolved (and continue to do so) as countries fine-tuned their approaches based on their (and the EU's) experiences and policy priorities.

From the context of the countries surrounding the North Sea, the effectiveness of renewable support schemes, whether at a national level or as part of a cooperation mechanism, would have a significant bearing on investment in and the development of offshore wind farms. This would consequently have a significant impact on the development of transmission infrastructure over the North Seas. In this internal deliverable, we discuss 1) different renewable support schemes. 2) the evolution and current implementation status of renewable support schemes in the countries surrounding the North Sea. 3) cooperation mechanisms for renewable support. 4) case studies on the implementation of cooperation mechanisms for renewable support.

In the countries of the North Seas, it is observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration have explicitly implemented a feed-in premium scheme while France too has moved to a feed-in premium system for specific technologies.² Belgium utilises a renewable obligation scheme in which the prices for offshore wind renewable certificates are treated such that they resemble a feed-in premium scheme. However, the method of administration of the feed-in premium may vary from country to country. Technology-specific competitive auctions are the most commonly used mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.

² In most cases a floating, also called sliding, premium is preferred. Unlike the fixed premium, the additional remuneration (or premium) paid to the renewable generators is adjusted depending upon the price that develops in the electricity market to ensure that the renewable generators receive a predefined price level. This predefined price level, also called the strike price, is set either administratively or through an auction.

Regarding harmonisation of renewable support schemes among these nations, the shift towards a feed-in premium can be considered a welcome move. Whether this evolution leads to greater coordination between these nations in administering renewable support (even leading to a cooperation mechanism between multiple nations) and if so, then what type of mechanism, remains a wide-open question.

Three cooperation mechanisms for renewable support schemes, namely: statistical transfers, joint projects, and joint support schemes, were introduced by the EC as part of the Directive 2009/28/EC. The aim of encouraging member states to facilitate the implementation of these coordination mechanisms is to provide more effective and cost-efficient exploitation of renewable resources. Cooperation on renewable support schemes between countries surrounding the North Sea could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. Furthermore, the “Clean energy for all Europeans” package proposes that “the Member States shall open support for electricity generated from renewable sources to generators located in the other Member States” (Article 5 of the renewable directive recast). This adds to the need for greater understanding of cooperation mechanisms. However, cooperation mechanisms for renewable support have rarely been utilised by the EU states.

From a meshed offshore wind development perspective, the implementation of a technology-specific joint support scheme appears to be a relevant alternative to consider for further discussion. Such a scheme would enable greater harmonisation in the support for the offshore wind farms. It would also lead to the development of the most cost-effective sites. Assuming the utilisation of an efficient method for calculating costs and benefits, this support scheme would aid in enabling a more balanced allocation of the costs and benefits between countries connected to the meshed system. Making the support scheme offshore specific could enable implementation of this scheme alongside the national support schemes while minimising negative cross-policy impacts. Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a “technology-specific joint support scheme”.

It can be inferred from the case studies presented that cooperation mechanisms have a higher likelihood of long-term success if there is a level playing field for stakeholders of all the participating countries. Importantly, cooperation will be most suited where similar market conditions exist within the cooperating states. A significant observed roadblock to implementing joint support schemes is that EU Commission targets and national interests do not always converge. Thus, countries may exit the cooperation mechanisms if they feel that the membership is not in their national interest.

CHAPTER 6: TRANSMISSION TARIFF DESIGN IN A MESHED OFFSHORE GRID CONTEXT

According to the European Commission, transmission tariff design is expected to have an impact on the development of offshore wind farms (OWF). Although the transmission tariff represents only a smaller fraction of the total costs of an OWF project, it may have an impact on the location and business case of these projects. For example, if the methodology of calculating the transmission tariff in a location imposes an additional risk to the



developer, the developer may prefer to move to a different location with a more favourable tariff structure, under the assumption that other parameters such as support schemes, market design, and wind availability are similar.

In this chapter, first, we provide the reader with an understanding of the theoretical aspects of transmission tariff design. This consists of discussion on alternatives for transmission costs distribution amongst grid users namely: economic methods, network utilisation methods and methods without locational components. This is followed by a discussion on dimensions of recovering transmission costs from grid users. Several options have been used in practice and discussed in theory. These extend from the type of charging (if energy or capacity-based) to periodicity of the charge. Finally, inter-TSO compensation mechanism is discussed.

This is followed by an analysis of the level of transmission tariff regime harmonisation between the different countries of the North Sea. In this analysis, we compare ten countries: Belgium, Denmark, France, Germany, Great Britain, Ireland, the Netherlands, Northern Ireland, Norway, and Sweden. For each country, seven relevant dimensions of transmission charges were analysed. The seven dimensions are: G-L Charges (cost allocation between load and generator). Type of connection charges (deep, shallow, super-shallow). Temporal price signal (consideration of the time of use in tariff design). Locational price signal (consideration of whether considers the location of use in the tariff design to indicate the difference in usage level of the network in a particular area). Inclusion of losses (consideration of losses in tariff). Inclusion of system services (considering inclusion of system services such as ancillary services and balancing energy in tariffs). Energy-related and capacity related components (Proportion in which transmission costs are recovered via energy-based components (€/MWh), capacity-based components (€/MW), fixed components (€) or a combination of the three).

A mapping of how ten nations adjacent to the North Sea deal with several aspects of transmission tariff design is presented. From this mapping, we can conclude that transmission tariffs are still unharmonized across the countries surrounding the North Sea. Both the amount of transmission costs levied on generation and the form of transmission charges vary considerably. There exists a risk that such a scenario could prove to be detrimental from the perspective of developing a meshed offshore wind infrastructure. It can impact the investment decisions of OWF and therefore impact the overall benefit extracted from the meshed offshore grid. The situation can also impact TSOs if cross-border flows created by the meshed offshore grid are not appropriately compensated. Therefore, greater harmonisation may be required.

CHAPTER 7: ECONOMIC INCENTIVES FOR INVESTMENT IN MESHED OFFSHORE GRIDS

Since the liberalisation of the power sector, the use of 'incentive regulation' has become a standard practice among European regulators. Furthermore, Article 13 (1) of the Trans-European Networks for Energy (TEN-E) regulation for PCIs mandates the use of dedicated incentives for projects that may be deemed to have higher risks for their development, construction, operation or maintenance (such as offshore transmission infrastructure). In the past few years, regulators have opted for a case-by-case regulation as a means to incentivise necessary or strategically important investments. Nevertheless, it has not substituted portfolio regulation.



We investigate the economic incentives that are necessary for the development of the offshore grid. This research extends the work of Glachant (2013) and Meeus and Keyaerts (2014) to present the combined impact that the general regulatory regime and dedicated incentives may have on the risk and remuneration for TSOs. A case study approach is utilized to substantiate the analysis. Regulatory structures of Great Britain, Germany, Denmark, the Netherlands and Belgium are assessed. These five countries were chosen because of their relevance to the development of offshore wind power.

This analysis is divided into two parts. In the first one, the default national regulatory frameworks are analysed. In the second, “dedicated incentives” for investments in these countries are evaluated. National regulatory regimes are analyzed based on four main economic aspects of regulatory regimes namely their capability to sufficiently remunerate TSO investments and to ensure their financeability, reduce the risk born by the TSO, incentivise TSO cost reduction and transfer efficiency gains and redistribution to final users. To analyze if these economic aspects hold on regulatory regimes, five main characteristics are investigated namely: the length of the regulatory period, the scope of the revenue cap (TOTEX versus building blocks), the tools to define allowances and efficiency targets (benchmarking versus cost and efficiency audit), the practical setting of the capital remuneration, the adjustment mechanisms. The impact of dedicated incentives on the risk and remuneration characteristics set by the general national frameworks for the TSOs is then analysed.

Since the previous study by Glachant (2013), the default regulatory frameworks of the countries analysed have not changed significantly in terms of their risk and remuneration characteristics. However, it is observed that recently, regulators have started providing additional dedicated incentives for necessary or strategically important investments.

In general, this qualitative analysis indicates that the application of dedicated incentives can be considered as a valid approach by countries that are likely to require significant investment in offshore grids. The trend of providing dedicated incentives modifies the risk and remuneration characteristics set by the general national frameworks. The application of dedicated incentives has provided a push towards a better balance of economic incentives in terms of the trade-off between risks and remuneration. However, in this approach, regulators must remain aware of the increase in risk due to the complexity of such mechanisms, especially in terms of information asymmetry and transparency.

CHAPTER 8: CROSS-BORDER COST ALLOCATION IN THE MESHED OFFSHORE GRID CONTEXT

The development of a Meshed Offshore Grid (MOG) would consist of the development of several projects with strong interactions and possible complementarity. Furthermore, these projects can be expected to involve several actors and borders. In such multi-jurisdictional projects, Cross-Border Cost Allocation (CBCA) would be crucial for ensuring the timely and effective development of such projects. Furthermore, the development of a meshed offshore grid will be evolutionary. Therefore, offshore interconnectors that are inherently multi-jurisdictional and built across borders can be considered an early step in the evolution of a MOG.



In this chapter, we discuss cross-border cost allocation for transmission infrastructure projects in the context of developing a meshed offshore transmission grid.

In the first step, CBCA decisions of three offshore interconnectors, namely: The Biscay Gulf interconnector, COBRACable and the EWIC interconnector. These decisions are assessed based on an analytical framework that is developed based on earlier work done by the Florence School of Regulation on the topic of CBCA. The framework consists of six dimensions, namely: significance threshold (based on total net positive benefit for a country) and EU funding interaction, market tests for ascertaining commercial viability, completeness of CBCA decision (an incomplete decision would mean that the NRAs agree on a cost allocation that assigns part of the costs to the Connecting Europe Facility (CEF)), CBCA based on CBA results, considering interaction between projects in CBCA decision and use of binding commissioning date commitments in CBCA decisions. In the second step, the insights from the first step along with the analytical framework are used as the basis for an analysis leading to a recommendation on good practices for executing CBCAs in the context of a meshed offshore grid development.

It is evident from this analysis that the six FSR recommendations continue to remain relevant for offshore infrastructure development including the meshed offshore grid. In the case studies, none of the projects received a **complete CBCA decision**, no **market tests** were conducted, nor any **binding commitments** incorporated in the CBCA. Large scope for improvement exists in these three aspects.

The use of a **CBA as the basis for the CBCA decision** is evident. With the implementation of the TEN-E regulation, PCIs are required to conduct a CBA based on the ENTSO-E CBA methodology. Therefore, it can be foreseen that CBA would be used as an input during the CBCA decision making process. It is observed that project developers are **exploring possible innovation in CBCA decisions**. This can be considered a positive step forward and as such project developers should continue to explore the possibility of applying innovation to CBCA.

Project interactions are being **considered** to the extent required by the ENTSO-E CBA methodology. However, no evidence of coordination between CBCA decisions of the complimentary project or any such consideration was observed. Finally, in the case studies under consideration, the **significance threshold** has not been used for requesting EU support. Not using the significance threshold for EU support is a good practice and should continue.

Specifically, in the context of the meshed offshore grid development, we highlight four key recommendations.

Recommendation 1: The coordination of CBCA decisions for complementary projects is recommended. This aspect would be further enhanced with a clustered approach in which a CBCA agreement is reached for a group of projects. Such an approach would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.



Recommendation 2: Formalization of the CBCA as a binding contract between the involved parties with a clear specification of non-compliance penalties, especially regarding commissioning dates, is recommended. In a multi-stakeholder environment, such a step can be foreseen to provide greater commitment towards the project by all parties, thereby enabling the avoidance of situations with “bridges to nowhere”.

Recommendation 3: It is recommended to revisit the interaction between the significance threshold and EU funding. This step would aid in more effective cost allocation by encouraging complete CBCA decisions as well as enabling effective EU funding allocation thus reducing avoidable delays in the development of these transmission infrastructure projects.

Recommendation 4: Ensuring complete CBCA decisions is recommended. The decision can consider scenarios with and without EU funding as well as with and without commercial revenues. Such a step would mitigate any delays that may occur due to renegotiations between project developers that may be necessitated by an adverse EU funding decision.

OFFSHORE GRID OPERATION

CHAPTER 9: THE IMPACT OF BALANCING MECHANISM DESIGN ON OFFSHORE WIND FARMS

In the current electricity directive 2009/72/EC (European Commission, 2009b), intermittent renewable resources are exempt from balancing responsibility. However, the recent Clean Energy Package (CEP) derogates the balance responsibility exemption (See Article 4 in (European Council, 2019)).

This research assesses current balancing mechanisms from the perspective of offshore wind participation both as a balance-responsible party (BRP) and as a balancing service provider (BSP). We also investigate whether the interests of offshore wind are aligned with the interest of the system as a whole. Therefore, we provide a third perspective to this analysis where we assess the same issues at a system level.

An analytical framework consisting of six dimensions was used to assess the above mentioned three perspectives. The six dimensions are: imbalance settlement rule, imbalance settlement period, product and service definitions, scarcity pricing, intraday market and integrated balancing market. We also consider what is stated regarding these different points in the Electricity Balancing Guideline (EB GL) which was adopted in late 2017. The EB GL is one of the eight adopted European network codes and guidelines for electricity which are grounded in the Third Energy Package. Key conclusions from this research are presented below.

1. **Imbalance settlement rule:** a single price rule for imbalance settlement is the best solution from all perspectives. The EB GL also supports this view.
2. **Imbalance settlement period:** a conflict between the user and service provider perspective occurs. The EB GL foresees a convergence to an imbalance settlement period of 15 minutes with possibility of temporary exemption.



3. **Product and service definitions:** These rules are relevant only from a system perspective and a balancing service provider perspective. The product and service definitions should be set so that they eliminate the barrier for entry for OWF. Smaller bid sizes and contract periods, a gate closure which is as close to real time as possible, and use of asymmetric balancing products are some key desirable elements of a market design suitable for offshore wind participation. However, some trade-offs may be required while selecting design parameters.
4. **Scarcity pricing:** Scarcity pricing is desirable from a system point of view, i.e. the total cost may reduce due to the possibility of attracting more market players and thus more competition. A balancing service provider too would benefit from the better valuation of its services. From a balance responsible party perspective, scarcity pricing could be considered an added risk, due to the possible occurrence of undesirable price spikes.
5. **Intraday market:** a well-functioning liquid intraday market with a gate-closure as close to real-time as possible would be beneficial from all three perspectives.
6. **Integrating balancing market:** greater integration of balancing markets would be desirable. However, the current market design needs to evolve further for effective realisation of the benefits from integration of balancing markets.

The summary of the six selected balancing mechanism concepts from the three perspectives is provided in the following table:

Table I: Summary of the current balancing mechanisms regulation from the three perspectives.

Dimensions	Perspectives		
	System	OWF BSP	OWF BRP
Settlement rule	Single pricing	Single pricing	Single pricing
Imbalance settlement period	Short	Short	Long
Product and service definitions	Costs and benefits of removing entry barriers need to be assessed.	Following rules are desirable to reduce entry barriers: - Smaller bid sizes - Smaller contract period, - Close to real-time gate closure	Indirectly affected
Scarcity pricing	Desirable (lower costs)	Desirable (Incentive to participate)	Undesirable (Risk of price spikes, but benefit if costs reduce)
Intraday market	Desirable (lower costs)	Desirable (Another trading opportunity)	Desirable (Lower costs)
Integrating balancing markets	Desirable (lower cost)	Desirable (Greater market liquidity)	Desirable (Lower costs)

1 INTRODUCTION

Offshore wind is expected to play a significant role in enabling the EU to meet its Greenhouse Gas (GHG) reduction and renewable energy target in the near and long-term future (European Commission, 2015). The recent offshore wind tenders in Germany which had a minimum price of 0.00 €/KWh (BMW, 2017) provide a clear insight into the viability of this technology.

The development of a robust offshore electricity grid infrastructure has the potential to deliver many benefits. Firstly, offshore grid infrastructure is regarded as crucial for the integration of renewable energy sources. Secondly, having a robust offshore grid infrastructure connecting overseas markets would have a substantial positive impact on long-term as well as the short-term security of supply (European Commission, 2016a). Thirdly, through investment in offshore grid infrastructure, more precisely in subsea interconnectors, electricity markets can be coupled across the sea, allowing a more efficient dispatch of generation and an overall increase in social welfare. Additionally, if markets were coupled, liquidity would be augmented, and more competition would be introduced.

Several studies (Such as: Cole et al., 2015; Egerer et al., 2013a; European Commission, 2014a; Flament et al., 2015; NSCOGI, 2012) show that a meshed offshore grid in the North Sea would lead to maximisation of the total net benefits. A very recent report of the European Commission (EC) demonstrates a potential for saving up to €5.1 billion in the reference year 2030 to be made by building a meshed grid instead of standalone connections of wind farms and point-to-point interconnectors (European Commission, 2014a). However, the development of this offshore meshed electricity grid in the North Sea would happen as an incremental process rather than as a so-called 'big bang' approach, even if the coastal states could readily agree on this as a mutually beneficial objective. It is likely that developers will concentrate in the short to medium term on building small-scale infrastructure projects, including interconnectors to which wind farms are attached. Over the long run, these interconnections could then be linked with each other to create a regional grid (Woolley, 2013a).

Work Package 7 (WP7) of the Progress on Meshed HVDC Offshore Transmission Networks' (PROMOTioN) Horizon 2020 project focuses on various legal, financial and economic aspects of developing an integrated offshore infrastructure. **Task 7.2** focuses on the development of an economic framework for the offshore grid in terms of three building blocks, namely: planning, investment and operation³.

The WP7.2 final report consists of a compilation of eight regulatory challenges that have been addressed and are related to three building blocks (See Figure 1):

³ Note that apart from the economic framework discussed in this report, the legal (WP7.1) and financial (WP7.3) frameworks, and development of a CBA methodology for meshed offshore grids (WP7.6) is addressed in separate tasks within WP7. Based on these tasks and corresponding deliverables, a final report WP7 will also be consequently published.

Offshore grid planning comprises three topics: CBA methods, onshore-offshore coordination, and public participation.

Offshore grid investment comprises four topics: cooperation mechanisms for renewable support, transmission tariffs, Investment incentives and CBCA methods.

Offshore grid operation focuses on the balancing mechanism in the offshore wind context

This report extends our intermediate report with the addition of three new topics: incentives, CBCA and the balancing mechanism. The remaining chapters are identical to the intermediate report.

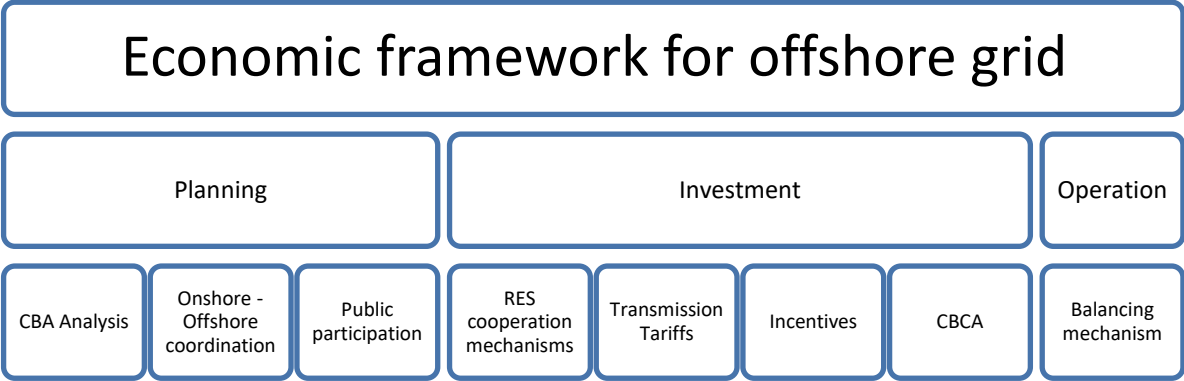


Figure 1: Illustration of the report structure

2 OFFSHORE GRID PLANNING I: COST-BENEFIT ANALYSIS FOR OFFSHORE ELECTRICITY GRID INFRASTRUCTURE

2.1 INTRODUCTION⁴

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 2.

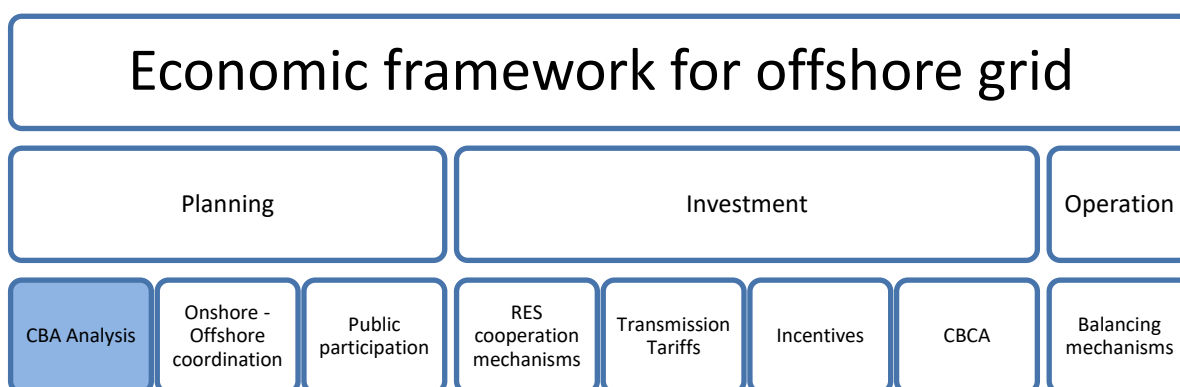


Figure 2: Illustration of the position of this chapter in the overall report structure.

There are various possibilities for investments in smaller-scale offshore infrastructure projects with varying benefits and costs. It is vital that a thorough evaluation of every project is conducted before any decision regarding its execution is made as a limited budget for such investments is allocated. The coordinated application of a cost-benefit analysis (CBA), a well-established decision support instrument (Courtney et al., 2013), to select and facilitate those energy infrastructure projects that bring forth the largest net welfare gain for Europe has been a significant step forward in that regard (Meeus et al., 2013). The idea behind a cost-benefit analysis is to assess and compare on an equal footing the advantages and disadvantages of alternative projects by considering the best available information.

Cost-Benefit Analysis (CBA) is a well-established tool to guide investment decisions in various sectors including the energy sector. However, only in recent years have we seen the development of an EU-wide standard methodology.⁵ The most well-known use of CBA methodologies in the EU energy context is the CBA methodologies for energy infrastructure published by ENTSO-E and ENTSOG (ENTSO-E, 2016a, 2015a; ENTSOG, 2015). According to Regulation (EU) No 347/2013, ENTSO-E and ENTSOG received the task to

⁴ The general findings described in this document are also discussed in (P. C. Bhagwat et al., 2017; Keyaerts et al., 2016)

⁵ In the history of the TEN-E programs, CBA was already recommended in the early 90s, but it was without obligation or proper guidance so that eventual results were not consistent.

develop these methodologies.⁶ There are multiple ways of performing a good CBA, but as the goal is to compare and select projects to prioritise, it is of foremost importance that these are evaluated using the same methodology.

The harmonised system-wide CBA methodology is applied by the ENTSOs to provide objective information uniformly about the projects taken up in the Ten-Year Network Development Plans (TYNDPs). In addition, the CBA methodology is relevant for: 1) Establishing a regional list of projects of common interest (PCIs). 2) Submission of investment requests by PCI promoters to National Regulatory Authorities (NRAs). 3) Decisions of NRAs on granting incentives to PCIs. 4) Providing evidence on significant positive externalities for the purpose of Union financial assistance to PCIs (ACER, 2017). PCIs are infrastructure projects with a pan-European impact identified by the EC as essential for completing the internal energy market (see box).

Projects of Common Interest (PCIs)

The first list of PCIs was published in 2013. The list is updated every two years and contains a selection of infrastructure projects with a trans-European impact. Electricity and gas transmission projects, smart grids and storage projects for both electricity and gas can be nominated. Selected projects may benefit from accelerated planning and permit granting, a single national authority for obtaining permits, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, and increased visibility to investors. Additionally, selected projects can access financial support. A total of €5.35 billion from the Connecting Europe Facility (CEF) is allocated for the period from 2014-2020 for this purpose (European Commission, 2016b). To be selected as a PCI, an electricity-related project needs to be part of the TYNDP, published by ENTSO-E, and its promoters need to conduct a CBA to demonstrate that it brings a net increase in pan-European welfare. On the basis of the CBA and regional priorities, winning projects are finally granted the PCI status. The full process of selection is shown in the figure below



Figure 3: The process of PCI selection for electricity (Meeus et al., 2013; Nyitrai, 2012; Sikow-Magny, 2012)

Currently, the major offshore electricity infrastructure projects with a trans-national impact, both point-to-point interconnectors and combined solutions, are part of the 2013 and 2015 PCI list⁷. The projects which applied for the 2015 list⁸ were assessed applying a CBA consistent with the ENTSO-E methodology approved by the

⁶ Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on Guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009, article 11. These methodologies have been continuously updated since discussion of them started in 2012 (ENTSOG, 2012).

⁷ Note that the research on this chapter of the report was completed before the publication of the PCI list 2017.

⁸ The list is available here: <http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0089&from=EN>

European Commission while earlier projects were evaluated using ad hoc methods. Below the latest relevant projects, which are part of the PCI list from the European Commission interactive map are shown.

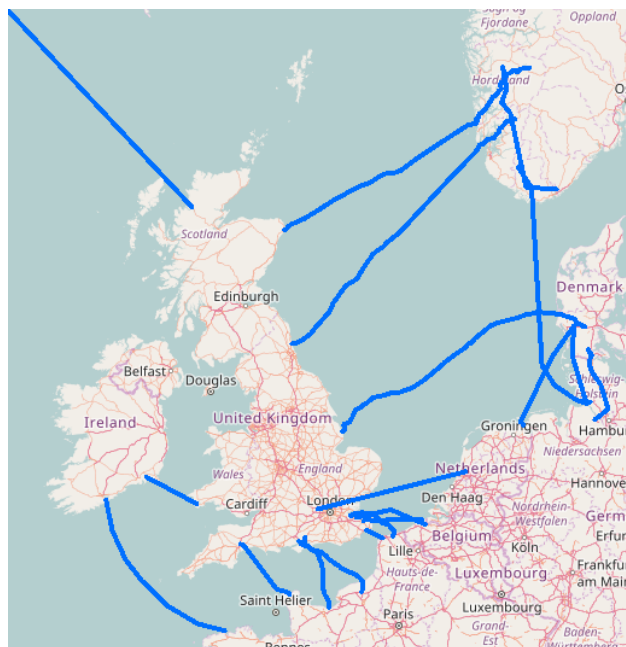


Figure 4: Illustration of offshore PCIs in the northern seas from the European Commission, interactive map⁹⁾

It should also be noted that results from the CBA are valuable in the process of making cross-border cost allocation (CBCA) decisions.

In this document, we focus on the CBA methodology applied to trans-European electricity infrastructure projects and discuss, both from a theoretical and from a practical point of view, its adequacy in the offshore context. More concretely, this document contains three objectives:

- To present a framework for a robust CBA with a focus on offshore infrastructure.
- To apply this framework to assess the ENTSO-E’s CBA methodologies (ENTSO-E, 2016a, 2015a, 2015b).
- To apply this framework to assess three case studies of offshore transmission infrastructure projects.

2.2 ANALYTICAL FRAMEWORK AND CURRENT PRACTICE

In this section, an analytical framework for a robust CBA methodology is presented. These best practices or guiding principles for a robust CBA methodology were identified by the Florence School of Regulation (FSR) over the course of the last years. More specifically, in this document we apply the theoretical framework initially introduced by Meeus et al., (2013). This framework has gone through several iterations¹⁰ and today has boiled

⁹ Interactive map accessed on 01/04/2019 – Link: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html

¹⁰ The framework has been discussed and refined on several occasions, including the EU’s Second cross-Regional Group Meeting of 29 September 2014, the FSR Policy Workshop of 24 October 2015, the FSR-BNetzA Forum of 6 February 2015, the Horizon 2020 BRIDGE meeting of 15 September 2015.

down to a checklist consisting of 10 guiding principles divided into concerns related to the input, the calculation, and the output of a CBA.

The presentation of the framework is done simultaneously with the assessment of CBA methodologies published by ENTSO-E, as their evaluation can serve as a concrete illustration clarifying the analytical framework. The assessed CBA methodologies are: the CBA for trans-European electricity infrastructure projects (ENTSO-E, 2015a), further referred to as CBA 1.0, the proposal for an updated version of the same CBA methodology (ENTSO-E, 2016a), further referred to as CBA 2.0, and the CBA methodology for cross-border harmonization of market design elements (ENTSO-E, 2015b). The ENTSO-E CBA 1.0 and 2.0 are evaluated because these methodologies serve as the basis (CBA 1.0) or could become the basis in the near future (CBA 2.0) if accepted by the EC) for the CBA executed by project promoters¹¹. Also, the CBA methodology for cross-border harmonisation of market design elements, with a focus on balancing markets, is taken up in the analysis. This CBA methodology serves for some elements of the CBA as an example of best practices.

Firstly, the evaluated CBA methodologies¹² are briefly introduced. After this introduction of the evaluated methodologies, ten key guidelines for a common method for CBA for energy projects are discussed. Each time, the guideline is explained, and the approaches of the methodologies are described. The first three guidelines relate to the input side of the cost-benefit analysis. The next five guidelines relate to the calculation of the net benefit, and the final two guidelines have to do with the output of the cost-benefit analysis. Finally, a table is presented summarising the assessment of the current implementations by ENTSO-E's CBA 1.0, CBA 2.0 and its CBA for market design projects.

2.2.1 INTRODUCTION OF THE ASSESSED CBA METHODOLOGIES

2.2.1.1 CBA 1.0 AND 2.0 FOR ELECTRICITY INFRASTRUCTURE BY ENTSO-E

Cross-border electricity transmission¹³ projects, both onshore and offshore, are deemed crucial to complete the European internal energy market. The common practice in planning energy infrastructure is national, rather than regional, leading to difficulties in implementing cross-border projects. Therefore, the EC decided to facilitate projects of this nature by providing them with a priority status, more precisely by listing them up as PCIs. To ensure an adequate selection of prioritised projects and value for money in the spending of public funds, a transparent, objective and common selection procedure based on economic rationale should be applied.¹⁴ The purpose of that procedure should be to assist in the selection of the optimal 'portfolio' of projects at the political level.

¹¹ See box: Update since September 2016

¹² In Annex I 7.1 two additional CBA methodologies for energy projects with a European impact are presented and assessed, namely: the ENTOG's CBA methodology for gas projects with a cross-border impact and JRC's CBA methodology for smart grid projects.

¹³ It should be noted that also large-scale strategically sited electricity storage projects could be an alternative to transmission projects to deliver similar benefits. As such, these projects are assessed using the same methodology.

¹⁴ Regulation (EU) No. 347/2013

It is in this light that ENTSO-E (ENTSO-E, 2015a) developed a guideline for a CBA methodology for electricity infrastructure projects with a cross-border impact. The EC approved this methodology in February 2015. ENTSO-E is required to update this methodology on a regular basis. Therefore, in April 2016 it published a draft for public consultation, further developing this methodology. The comments of this public consultation were considered, and on the 29th of July 2016, a revised version was published for the official opinion of ACER. It is this version we refer to as CBA 2.0 in this document.¹⁵ It is essential to add that the ENTSO-E CBA methodology is a reference for the improvement of planning processes in many countries for national projects.

Update since September 2016 (ACER, 2017)

On the 21st of September 2016, ACER sent a letter to ENTSO-E, taking note of additions to ENTSO-E's CBA Methodology submitted on the 29th of July 2016 and invited ENTSO-E to submit a new, complete version implementing all the foreseen improvements.

On the 6th of December 2016, ENTSO-E sent a letter to the ACER stating that, in line with the letter sent by ACER on the 21st of September 2016, ENTSO-E had withdrawn the draft CBA of 29th of July 2016. Afterwards, on the 6th December 2016, ENTSO-E submitted a new document "draft CBA methodology 2.0".

ACER published its opinion on that new draft on the 6th of March 2017. In that opinion, ACER encourages ENTSO-E to adapt the "draft CBA Methodology 2.0" before submitting it to the EC for approval. In the opinion of ACER, and consultations with the European Commission (EC) and the Member States (MSs), the document can be revised again after which it is submitted to the EC. The EC can approve or reject the CBA 2.0 methodology, and if accepted, the methodology will be published in the Official Journal. This decision by the EC was expected by Spring 2017 (ENTSO-E, 2016b).

However, the 2nd ENTSO-Guideline for cost benefit analysis of grid development projects was approved by the European Commission on September 27, 2018 (ENTSO-E, 2018a). In this document the "draft CBA Methodology 2.0" (ENTSO-E, 2016a) was assessed.

2.2.1.2 CBA FOR MARKET DESIGN PROJECTS BY ENTSO-E

A very recent implementation of CBA is the ENTSO-E methodology for CBA of market design projects. This methodology was developed after ENTSO-E identified that the draft Network Code for Electricity Balancing (NC EB) (ENTSO-E, 2014a) would benefit from CBA to be conducted in support of various decisions all related to cross-border balancing initiatives. More precisely, CBAs are deemed to be necessary to support TSO's proposals to modify the European integration model, to indicate the implications of the application of the TSO-BSP (Balancing Service Provider) model for the exchange of balancing capacity or energy, and to quantify the impact of a harmonisation of the imbalance settlement period. In this document, we comment on the general CBA methodology proposed (ENTSO-E, 2015b). Next, on the general methodology, an application of this framework assessing the effect of the harmonisation of the imbalance settlement has been developed (ENTSO-E, 2015c).

¹⁵ The CBA methodology 2.0 submitted on the 29th of July 2016 was withdrawn by ENTSO-E on ACER's request after the finalization of this internal deliverable (see box).

2.2.2 INPUT TO COST-BENEFIT ANALYSIS

On the input side of cost-benefit analysis, there are three implementation issues: 1) considering project interaction, 2) organising the data gathering process and 3) provision of disaggregated cost numbers.

2.2.2.1 CONSIDERING PROJECT INTERACTION

Why is project interaction relevant, especially for offshore grids?

In network systems like the electricity and gas systems in Europe, the actual value of an infrastructure project must be assessed considering the interaction of the project with the current and future system. When this is done, potential positive or negative synergies with other proposed projects can be found. Positive synergies mean that the economic value of the combined projects exceeds the stand-alone values of the projects, while for negative synergies the value of the projects diminishes when they are combined.

This discussion is particularly relevant for offshore grid infrastructure as there are many degrees of freedom in the way to interconnect different countries via the sea. In an extreme case, an interconnector project could be highly beneficial when the construction of another planned project is not considered, but could become a stranded asset if it is. Also, a subsea interconnector could be very complementary with, for example, a planned onshore cross-border transmission line. In that case, the construction of this onshore cross-border transmission line could augment the available capacity and/or commercial value of the offshore connector significantly.

More generally, an offshore grid is built up almost from scratch, and this implies that the construction of one offshore cable has a greater potential to impact the value of another planned offshore project than is the case with onshore cables. Thinking along these lines, it could be argued that the anticipation of the future development of other projects is of greater importance for the correct estimation of the added value of a planned project in the offshore context compared to the onshore context.^{16,17}

How can project interaction be considered in the CBA method?

Project interaction can be considered in the cost-benefit analysis through 1.) the reference grid or baseline against which the projects are assessed and; 2.) the project definition.

First, to identify potential synergies, projects should be assessed against multiple common reference grids. A minimum standard could be to assess the value of a project against a reference grid that considers the business-as-usual grid and all other PCI projects (take-one-out-at-a-time, TOOT), and against a reference grid that considers the PCI is assessed against only the business-as-usual grid (put-one-in-at-a-time, PINT). None of these two extreme variations of the baseline can be deemed to be 100% correct. In general, the value estimation by applying TOOT is rather conservative, while applying PINT, the assessment might be overly optimistic. What

¹⁶ Gorenstein Dedecca et al., (2017) add: "Typology, modelling and simulation factors interact to result in radically different offshore grid pathways, which exhibit strong path dependence."

¹⁷ "Enhanced Transmission Planning Methodologies" can be found under the deliverables of WP8 of the E-highway 2050 project (<http://www.e-highway2050.eu>)

matters is the fact that a significant difference in the value of the infrastructure project against both baselines signals interaction with other projects. If project interaction is signalled, then a supplementary analysis is required.

Second, complementary projects should preferably be clustered and defined as a single project for their assessment. It is considered a difficult exercise to define the criteria on the basis of which projects can be clustered. Clear rules need to be established to avoid over-clustering which could lead to the development of inefficient projects. Two criteria are identified: the amount of additional benefit which is delivered to the 'total cluster' by the inclusion of another project, and the 'time criterion', more precisely how far apart in time the development of the clustered projects can be. A trade-off must be found between the setting of arbitrary thresholds and defining criteria which allow for a substantial degree of subjectivity. The time criterion is especially relevant for offshore grid infrastructure as the construction times are typically significantly longer than for onshore grid infrastructure.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The ENTSO-E CBA 1.0 method uses a single baseline that includes the existing grid and non-PCI investment that has been included in the TYNDP. There is no assessment of the proposed project against a baseline that additionally includes other potential projects of common interest, making it difficult to discover negative synergies between potentially rivaling projects. CBA 2.0 continues to rely on a single baseline but offers encouragement to the project promoters to do their additional analysis. This is a step in the right direction, but because this further analysis is not mandatory, discrepancies could arise in the CBA output on which project selection can be based. The ENTSOG methodology for cross-border gas projects is best practice for this criterion, as in this methodology each PCI project has to be compared against two baselines, which represent two extreme variations on the forecasted reference grid (ENTSOG, 2015).

Also, CBA 1.0 shows shortcomings against best practices by strictly relying on arbitrary thresholds to define meaningfully grouped projects, both regarding the additional benefit to the 'main project' as for the 'time criterion'. In CBA 2.0 the clustering rules are updated. In the box below, an overview of the changes and diverging opinions of FSR and TenneT on these changes is shown.

Update 1 for clustering: time criterion

CBA 1.0: The commissioning dates of projects to be clustered cannot be more than five years apart.

CBA 2.0: Projects can be at most only one 'maturity stage' apart.

Maturity stages can be a step forward, but should be well defined. As defined now, there is too much room for interpretation.

Update 2 for clustering: quantification of additional benefit of an individual project to the total cluster



CBA 1.0: Every project in a cluster must contribute at least 20 % to the total grid transfer capability.

CBA 2.0: Projects can be clustered if one project cannot perform its intended function without the realisation of another project.

CBA 2.0 does not represent a significant improvement in these aspects as it removes any explicit requirements regarding quantitative evidence of positive synergies to be provided by project promoters. In CBA 2.0, a clear description of what is meant by ‘the intended function’ and an explicit requirement for quantitative evidence should be added.

ENTSO-E CBA for market design

The nature of the interaction between projects is different for infrastructure and market design. In the CBA methodology for electricity infrastructure projects, the interaction of the development of other projects on a particular infrastructure project is investigated. In the context of this CBA methodology for market design, the interaction between the choice of a certain design option in jurisdictions outside of the market design project on the choice for a design option in the particular jurisdiction is investigated.

The methodology for market design is clear that a common BAU baseline (called counterfactual), which is not necessarily the current status quo of the power system, should be compared to that baseline, including the different design options (called factual). Also, it is explicitly mentioned that the interaction of options that are implemented across multiple countries on a design option for a certain country should be investigated. However, it is added that because of limited resources it might not be possible to assess all combinations of options and countries. The pragmatic solution proposed is to assume that the factual and counterfactual are the same for all countries to reduce the planning cases.¹⁸ The way in which interaction affects the CBA outcome in the context of electricity infrastructure investment and market design harmonisation is different, but the overlying principles of dealing with this problem are similar.

2.2.2.2 DATA GATHERING PROCESS

Why is the data gathering process relevant?

All assessments rely on forecasted data of demand, supply, fuel prices, conversion factors, etc. Considering that the conventional time horizon for the assessment of infrastructure investment is twenty years or more, there can be different views on the forecasted numbers. To the extent that each project uses project-specific data as input into the cost-benefit analysis, comparing projects becomes impossible.

How can it be dealt with in the CBA methodologies?

¹⁸ For example, by doing so in a case where there are two countries and two options (A & B) to be implemented next to the BAU (counterfactual (C)) the number of planning cases to be studied reduces from 9 cases, consisting out of 1 counterfactual (CC) and 8 factual (AA, AB, AC, BA, BB, BC, CA & CB) to 3 cases, consisting out of 1 counterfactual (CC) and 2 factual (AA & BB).

A common dataset with appropriate granularity and geographical scope remedies that issue. This dataset can be built up from existing forecasting exercises such as the EU's Energy Roadmap 2050 scenarios.¹⁹ The process to collect data should be transparent and contestable, in the sense that users of the infrastructure (consumers, generators), regulatory authorities and project promoters have the opportunity to propose and challenge the numbers. Such a process provides an implicit consistency check and a minimum validation of the data.

What is current practice in the CBA methodologies?

ENTSO-E for electricity infrastructure

The data gathering process described in ENTSO-E's CBA 1.0 and 2.0 is aligned with the data collection in the context of the TYNDP for electricity transmission infrastructure. For TYNDP electricity, ENTSO-E predefines several scenarios with subsequent stakeholder consultation to validate the assumptions and parameters. Expectations about local developments feed into the process through their inclusion in the assumptions of the different national network development plans.

As part of the TYNDP electricity 2018, ENTSO-E is improving the diversity of scenarios by fostering more stakeholder input in the selection of scenarios. ENTSO-E and ENTOSOG (for TYNDP gas 2019) are also co-developing their respective TYNDP scenario sets, which are also a positive evolution as the value of electricity and gas projects is not completely independent.

ENTSO-E CBA for market design

As in CBA 1.0 and 2.0, also for CBAs in the context of the NC EB, it is strongly advised to use the same dataset used for the TYNDP when it comes to market data. For cost data, the source may be the TSOs or other relevant, credible parties. Moreover, also, public institutions, e.g. Eurostat, and/or private institutions, e.g. IEA, may be used as stated in the guidelines as is also the case in electricity infrastructure methodology, as either directly stated or implied via TYNDP processes. The general principle, explicitly stated in the document, is that the data are collected from a widely-accepted source.

2.2.2.3 DISAGGREGATED REPORTING OF COST DATA

Why disaggregated reporting of cost data is relevant, especially for offshore grids

Besides the common data, the input to the cost-benefit analysis includes the costs of implementing the specific project. These costs should be reported in a disaggregated format to allow benchmarking of the cost components, with respect for the confidentiality of commercially valuable information.²⁰ This input criterion is of particular importance for offshore grid infrastructure, the reason being that offshore grid technology is rather immature. As such, the costs, for both investment and operation, are highly uncertain. A global aggregated cost figure alone is not sufficient information.

¹⁹ Another example is the 2030 TYNDP data, for the construction of which both top-down and bottom up are used. Top-down refers to using European targets as a starting point. Bottom-up refers to mainly the usage of data from national TSO based on national development plans to build up scenarios.

²⁰ It is not argued that this information should be publicly disclosed, but the officials (e.g. NRA representatives, MS representatives and other relevant stakeholders) evaluating the PCI application should have an insight into the costs on a more disaggregated level.

If cost reporting is disaggregated, it is a lot easier to detect discrepancies between the cost drivers of different projects. Also, instead of providing a point estimate per cost component, the provision of a cost range, especially for immature projects, is best practice.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The CBA 1.0 method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. Disaggregated reporting would allow the cost items to be benchmarked against the ACER database of unit costs for electricity infrastructure investment (ACER, 2015a).

Also, CBA 2.0 provides a specific list of costs that must be considered when evaluating the total project costs, but no explicit obligation to report these different cost components is demanded. Moreover, CBA 2.0 introduces a 'complexity factor' by which the default investment cost of a project under consideration or in the planning phase should be multiplied. This was done to provide as much meaningful information as possible about a project in the early stages when not much is known about the project (e.g., routing) yet. The magnitude of this factor, set and explained by the project promoter, is arguably highly subjective, but is a step in the right direction compared to CBA 1.0 because it seeks to provide additional information about the causes of the reported project costs.

ENTSO-E CBA for market design

In the methodology, it is not explicitly stated that costs should be reported in a disaggregated manner when performing a CBA. However, again, the different types of cost which should be taken into account for these kinds of projects are enumerated.

2.2.3 CALCULATIONS OF COST-BENEFIT ANALYSIS

Five implementation issues should be considered when calculating the net benefit of the projects that are under assessment: 1) using a common list of significant effects, 2) disregarding distributional concerns, 3) providing explicit algorithms, 4) using a common discount factor, and 5) dealing with uncertainty.

2.2.3.1 USING A COMMON LIST OF EFFECTS

Why is using a common list of effects relevant?

To assess projects on the same footing, it is important to use a common list of effects, which are the benefits of the CBA. Rather than trying to be comprehensive for all projects, the CBA should focus on a reduced list of effects that are relevant for all projects because some benefits might only be relevant in very specific cases and some benefits might overlap. Not reducing and harmonising the list of effects renders it difficult to compare the outcome of a CBA for different projects.

How can it be dealt with in the CBA methodologies?



A comprehensive list of possible effects includes 1) the impact of the project within the electricity (but also gas) system, 2) the externalities of the project, and 3) the macroeconomic effects. Meeus et al., (2013) have further explored these three types of effects for electricity; their analysis is summarised below (Figure 5, left side).

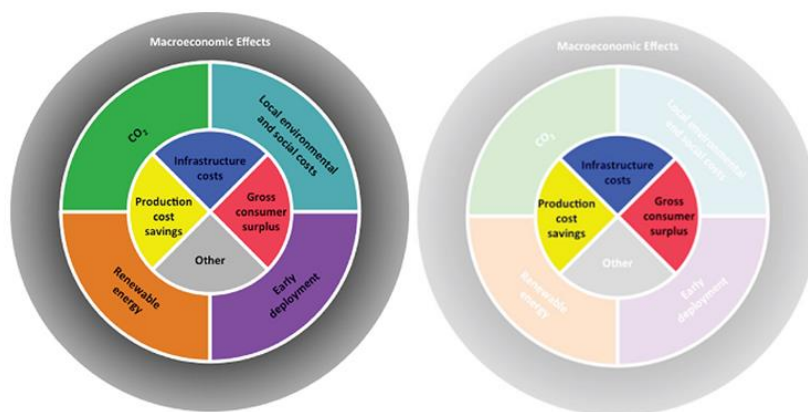


Figure 5: Illustration of the comprehensive list (left) and a reduced list of effects (right) for electricity transmission projects
Source: Meeus et al., (2013)

The electricity system effects include the impact on the gross consumer surplus (due to changes in consumption volumes), the impact on the production costs (more efficient dispatching, balancing or ancillary services in the short term and avoided investment in the long term) and the impact on the infrastructure/system costs. Additionally, there could be other market effects such as increased competition or liquidity. Finally, due to investment in infrastructure or enhancement of market design, the Security of Supply (SoS) could improve in the concerned areas. An increase in the SoS can be included in gross consumer surplus after the determination of a value of lost load (VOLL). The VOLL can be further determined per country, consumer type, hour, magnitude, and duration of the outage.²¹

The externalities include the the benefits of early deployment of new technology, as well as the impact of the project on carbon-dioxide emissions, the integration of renewable energy sources, and social and environmental costs, . The macroeconomic effects include the creation of jobs and the overall increase in economic growth.

A smart reduction of the aforementioned effects (see Figure 5, right side), allows a leaner cost-benefit analysis that monetises in the first order those effects that are important for all projects, with the possibility of supplementary analysis in the case that a specific benefit is significant for a particular project.

Some effects can be disregarded because they are covered partially or entirely by another effect; counting these effects separately would lead to double counting of the benefit. For instance, in Europe, the benefit of reduced carbon-dioxide emissions is (partly) internalised in the production costs through the EU ETS price.²² Similarly, social and environmental costs are usually included in the project costs by complying with any restrictions in the

²¹ Exemplary values can be found on <http://blackout-simulator.com/>, a tool for the calculation of the damage of a blackout.

²² The benefit of reduced carbon-dioxide emissions is fully internalized under the assumption that the EU ETS price reflects the cost of the damage done by CO2. This is (according to most stakeholders) not the case at current carbon prices.

building permit.²³ If there are justifications for CO2 emissions not being accounted for in the EU ETS price used in simulations, and residual social and environmental costs that are not mitigated by additional project measures, the remaining costs/benefits could be reported separately. The benefit of improved integration of renewables is typically also covered in the production cost savings by having more efficient dispatching of renewable energy sources. The benefit of advancing the roll-out of innovative technologies, which might be significant for offshore HVDC technology or smart grid projects, is usually internalised in the infrastructure costs through the different EU and national policies to fund innovation.

Some effects can be disregarded because they are roughly the same for all projects. For instance, the macroeconomic effects are likely to be similar for all projects: they create some additional jobs during the implementation stage and are in general a driver of economic growth.

That reduces the list of effects to consider for the electricity system effects, which are consumer surplus, infrastructure/system costs, production cost savings and other market effects. Remaining benefits/costs due to reduced carbon emission or social and environmental costs not captured by electricity system effects can be reported separately if there are sufficient justifications to do so.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

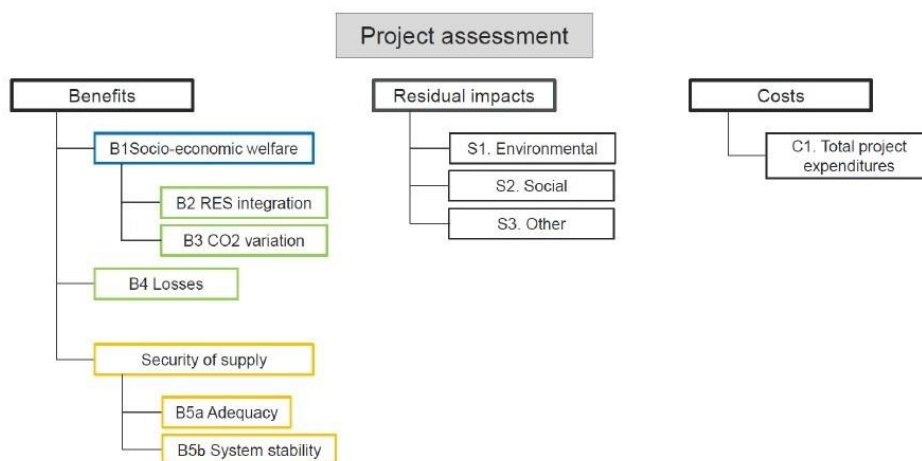


Figure 6: Effects to be considered in the project assessment in ENTSO-E's CBA 2.0 for electricity infrastructure (ENTSO-E, 2016a).

ENTSO-E discusses a set of effects that need to be included in the assessment. In CBA 1.0 7 benefits are identified which should be quantified (not always monetized) for each project, and for CBA 2.0 this list is reduced to 6 benefits as can be seen in Figure 6.

²³ Examples are measures that mitigate certain social or environmental effects. Additionally, there could be 'residual social and environmental costs' to cover the social and environmental costs (if justified) that are not internalized in project costs.

In CBA 2.0, the SoS indicators are redefined. Now a clearer distinction between the effect of a project on (short-term) system security and (long-term) system adequacy is made. Regarding the residual effects, in both CBA 1.0 and 2.0, it is mentioned that as far as environmental and social mitigation costs are concerned, the costs of the measures taken to mitigate the impacts of a project should be included in the project cost. However, some impact may remain after these measures are implemented, and this is reported separately. The RES integration indicator was included mainly because RES integration is mentioned separately in the Regulation and EU policy objectives.²⁴ The CO₂ indicator was also partly driven by this explicit mentioning. The methodology explicitly warns against double counting.

Also, the assessment of the benefits of a storage project is updated in CBA 2.0., more precisely the assessment of the benefits regarding the flexibility of the system, one of the most if not the most important benefit of storage projects, is described more in-depth.

ENTSO-E for market design

A list of 18 effects, costs, and benefits, is summed up. After analysis, these 18 objectives were reduced to an assessment structure consisting out of two layers. The first layer includes eight pass/fail conditions, more specifically minimum standards, which have to be fulfilled by any planning case. The second layer contains three metrics for benefits and two metrics for costs. It is emphasised that the enhancement of pan-European social welfare, comprising no less than ten objectives, is, in general, the most significant benefit to be accounted. The two other benefits include a metric regarding the enhancement of system security if there is any value placed on additional security above the minimum threshold and a metric concerning the support to the achievement of EU E-RES targets. Costs are split up into two categories; the cost of implementation and the impact on market parties regarding additional technical or IT requirements.

2.2.3.2 DISREGARDING DISTRIBUTIONAL CONCERNS

Why disregarding distributional concerns is relevant

The implementation of an electricity and market design project is likely to affect the distribution of welfare among economic agents. However, distributional concerns are best treated outside of the cost-benefit analysis through redistributive measures such as taxes. The objective of the CBA assessment is to perform a purely economic analysis to find out if a project is overall welfare enhancing.

What is current practice in the CBA methodologies?

ENTSO-E for electricity infrastructure

ENTSO-E's CBA 1.0 and 2.0 focuses explicitly on pan-European benefits and mentions: "Project appraisal is based hence on analyses of the global (European) increase of welfare". This means that the goal is to support the projects which are the best for the European power system. As such this principle is respected.

ENTSO-E for market design

²⁴ E.g. The 20-20-20 goals

In the ENTSO-E methodology for market design projects, it is explicitly stated that only economic benefits should be considered, not welfare transfers. Also, it is mentioned that the NC EB does not provide any guidance to the weighting of welfare for consumers or producers. Other tools, designed specifically with redistribution in mind, would be more appropriate in this role.

2.2.3.3 EXPLICIT ALGORITHMS FOR CALCULATING THE NET BENEFIT

Why is using an explicit algorithm for calculating the net benefits relevant?

To achieve a transparent assessment of the projects, the algorithms used for calculating the net benefit should be stated explicitly to account for the model imperfections.

How can it be dealt with in the CBA methodologies?

The model should be clear on the geographical scope, the temporal granularity and to what extent technical and market constraints have been included. Additionally, a common, preferably open-source, model could be used to make the assessment perfectly contestable by allowing interested parties to play with the assumptions while assessing potential investments. In the UK, for instance, the national CBA tool for interconnectors has been made publicly available by the regulated transmission system operator, allowing third parties to make their own assessments of their potential interconnector projects.²⁵

Considering the effects that are to be assessed, the calculation models should be able to calculate the changes in the gross consumer surplus, the infrastructure costs, and the production cost savings. This typically requires a consistent combination of network and market models, representative demand and supply curves, and a complete set of consistent input data. For calculating other market benefits, more advanced market models are required, for instance, models that can capture market power.

To demonstrate the need for more advanced supplementary analysis, indicators, such as market concentration indices, could be used.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

The methodologies discuss explicit requirements for the model to calculate the net benefits. A combination of market and network simulations, being used iteratively, is suggested, as these complement each other. Alternatively, a flow-based simulation, implicitly containing both a representation of the market and the network, can be used.

ENTSO-E CBA for market design

The guidelines are clear that that open access should be granted to all market participants so that they can use it for their own analysis.

²⁵ See National Grid's Network Options Assessment Report Methodology, 30 June 2015.

2.2.3.4 COMMON DISCOUNT FACTOR

Why is using a common discount factor relevant?

It is necessary to correct the time-value of those benefits that are in the far future, compared to those that are captured immediately. This raises the question of what discount factor to use: a high number attaches more value to immediate benefits, whereas a low number is relatively more favourable for future benefits.

Whatever the exact number, it is recommended to use the same social discount factor for the economic assessment of all projects.²⁶ That approach allows discovering the best projects regardless of local risk conditions, which for most concerned projects are likely to be similar as they would obtain the PCI (quality) label. For the financial analysis, however, it is essential to use a project-specific financial discount factor.

What is current practice in the CBA methodologies

In all evaluated methodologies, a common discount factor of 4% for all projects has been adopted. It is added that this discount factor should be regularly updated.

2.2.3.5 DEALING WITH UNCERTAINTY

Why is dealing with uncertainty relevant?

To obtain a robust analysis, uncertainty in the baselines as in market and cost parameters should be addressed.²⁷

How can uncertainty be dealt with?

Broadly, two options can be used to deal with uncertainty. Firstly, (macro-economic) multi-scenario analysis, e.g. scenarios differing on the values of the main input data. Under multi-scenario analysis, several point estimates of the benefits, (with or without a certain probability), are the output of the analysis. Additionally, sensitivity analysis can be done for key parameters.

Secondly, stochastic analysis can be applied, e.g. a Monte Carlo type analysis whereby correlated random values are drawn from distributions. When stochastic analysis is applied, the output of the assessment is a distribution instead of point estimates. In the extreme case, when assessing numerous scenarios in a multi-scenario analysis, the results of the multi-scenario analysis should converge with these stochastic analyses.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

In the calculation of both ENTSO-E 1.0 and 2.0, the usage of (macro-economic) scenario analysis is strongly advocated. In addition to scenario analysis, sensitivity analysis is suggested. While the CBA 2.0 discusses the

²⁶ Private discount rates might be systematically higher than the correct social rate of discount (see e.g. Solow, (1974)

²⁷ It should be noted that next to uncertainty about the evolution of the system also technical uncertainty is significant for offshore grids. The protection of HVDC is still a difficult problem, which might cause the interruption of HVDC operation. Reparation can take a long time, leading a serious interruption of cross-border trade or significant foregone revenues for offshore wind generators. This technical uncertainty should be included in the scenario and/or sensitivity analysis.

contents of scenario analysis, it does not lay down the specifics for all details, as is done in CBA 1.0. The argument for doing this is that this is left to the requirements of the study (e.g., an edition of the TYNDP) at hand.

Also, in CBA 1.0 it is mentioned that one top-down scenario should be defined as a reference scenario. It is explicitly stated that ENTSO-E shall state the order in which scenarios have to be analysed and that at least two scenarios should be analysed to ensure robustness to different evolutions of the system. In contrast, in CBA 2.0 this explicit rule to analyse at least two scenarios is not stated, the need for scenarios within the CBA process is reflected (ENTSO-E, 2016c). Also, it is mentioned that no scenario can be defined as a “leading scenario.”

ENTSO-E for market design

The ENTSO-E methodology for market design recommends using only one scenario from the TYNDP scenarios with additional sensitivity analysis, arguing that the typical time horizon of ten years is relatively short and that more scenarios would unnecessarily add complexity. The (correct) remark is made that the number of scenarios used is intertwined with the horizon of the analysis, namely the longer the horizon, the more additional scenarios are useful. This methodology argues that as default one scenario drawn from the TYNDP, with additional sensitivity analysis, should be preferred over scenario analysis to reduce complexity. Only if the planning horizon exceeds ten years, it is advised to use two scenarios to ensure the robustness to different evolutions of the system.

2.2.4 OUTPUT OF COST-BENEFIT ANALYSIS

On the output side of cost-benefit analysis, there are two implementation issues: 1) disaggregated reporting of benefits, 2) making the final assessment of the projects.

2.2.4.1 DISAGGREGATED REPORTING OF BENEFITS

Why is disaggregated reporting of benefits relevant, especially for offshore grids?

Even though the overall pan-European benefit of the project is the most important decision variable, the disaggregated reporting of benefits regarding their regional distribution and the specific benefits of a project provide additional insights.

The reporting of regional benefits is of particular importance considering the value of the CBA output to also support decisions regarding cost allocation, exceptional regulatory incentives or financial assistance. This is especially relevant as in the case of a meshed offshore transmission project. It is expected that the overall pan-European benefit of such a project is positive, but there will always be several nations benefiting significantly while other ones might even end up losing (Egerer et al., 2013b; Joao Gorenstein Dedecca et al., 2017; Konstantelos et al., 2017). Such an asymmetric distribution of costs and benefits complicates Cross-Border Cost Allocation (CBCA) discussions. As the benefit of a nation might not be proportional to the cost of the transmission assets installed within its territory, the application of the territorial principle²⁸ can be hard to justify and potentially block the development of future projects.

²⁸ The territorial principle is the default CBCA mechanism, it implies the costs of the assets constructed on the territory of an MS should only be allocated to that MS. The mapping between costs and benefits is disregarded and assumed to be proportional. Better suited alternatives will be discussed in future deliverables.

What is current practice in the CBA methodologies?

ENTSO-E CBA for electricity infrastructure

Both in CBA 1.0 and 2.0 it is left to the project promoters to provide geographically disaggregated reporting, whereas this should be a mandatory requirement (for the reasons discussed above).

ENTSO-E CBA for market design

It is stated that although the overall European societal welfare is the relevant objective of a market design project, nevertheless, the CBAs shall report on regional and country effects for information purposes, which is best practice.

2.2.4.2 FINAL ASSESSMENT OF THE PROJECTS

Why this final assessment is relevant, especially for offshore grids

The usefulness of performing a CBA analysis is twofold, firstly the estimated net benefit indicates if it is worth executing a project and secondly this result also allows different projects to be compared with each other and as such to select the projects to be prioritised. The prerequisite for evaluating and comparing the net benefit of projects is that the results of the analysis are expressed in monetary terms. However, transparent adjustments might be justified to accommodate certain considerations such as double counting of effects, potential synergies with other projects, and uncertainty; all these concerns can be treated within the CBA methodology as elaborated throughout this chapter. The whole idea of having a common CBA method is to have an economic, rather than a political assessment of PCIs. If experts resort to indicators rather than monetization of the value of a PCI, they basically push the decision back to the political level.

Full monetization is of particular importance when evaluating offshore projects as they are expected to score high on several benefit indicators as they can connect both, countries separated by seas and (possibly) offshore generation. Typical high-scoring benefit indicators are socio-economic welfare increase, security of supply and the integration of renewables. If the final assessment includes both monetized effects and other indicators, there is not only a risk of double counting effects, but it also implies implicit monetization of these quantitative and qualitative indicators, leading to a less transparent and more subjective assessment.

How can a final assessment be dealt with?

More clear guidelines are strongly advised in this respect, and the development of a list of figures for difficult to quantify indicators, such as the value of lost load (VOLL), on a Union-wide basis should be a priority to facilitate an explicit monetization. It is not argued that for example the VOLL should be equal for all of Europe during all periods of the year, but at least a common method could be agreed upon to determine monetary values. An example of a difficult to determine parameter for which a value was agreed upon in the past is the common discount factor.



What is current practice in the CBA methodologies?

ENTSO-E for electricity infrastructure

Both in ENTSO-E CBA 1.0 as in 2.0, a form of multi-criteria analysis is applied with the explicit monetization of several effects and quantitative and qualitative indicators for other effects that are arguably difficult to monetise.

One indicator which is hard to monetize is the Security of Supply (SoS). In ENTSO-E 1.0 it is mentioned that given the high variability and complexity of VOLL, calculating project benefits using market-based assessment will only provide indicative results which cannot be monetized on a Union-wide basis. In ENTSO-E 2.0 it is stated that if project promoters of a specific cluster agree, it is possible to give the monetized figure of SoS as additional information next to the Expected Energy Not Served (EENS) value in MWh. Regarding the variation of losses in ENTSO-E 2.0 more effort has been seen to monetize this effect. Also, a calculation methodology is explicitly written out.

ENTSO-E for market design

In the methodology, the emphasis is laid on the fact that a pure CBA, defined as a CBA in which all costs and benefits are monetized, is always preferred over a multi-criteria assessment if possible. It is stated that if the impact of all most relevant aspects of social welfare can be monetized, the other objectives related to social welfare, e.g. the impact on the liquidity of the market, must be used rather for information purposes. However, how this full monetization should be implemented practically is not described.

2.2.5 TEN KEY GUIDELINES FOR A COMMON METHOD FOR COST-BENEFIT ANALYSIS

Table 1 provides a summary of the aforementioned guidelines for a robust cost-benefit analysis method. The dimensions for which improvement should be made are highlighted in orange. Additionally, the dimensions which are of even greater importance in the offshore context versus the onshore contexts are marked.

It should be noted that the key principles which are identified as even more important in an offshore context compared to an onshore context are those highlighted in orange for the ENTSO-E CBA 1.0 and 2.0 methodology. There are remaining concerns regarding the respective methodologies for implementing CBA which are not addressed in any of the evaluated CBA methodologies. For instance, none of the CBA methodologies explicitly obliges the disaggregated reporting of costs, which is necessary to allow easy efficiency benchmarking of costs. Transparency should be a priority, especially for projects that receive a significant amount of public funding.

Table 1: 10 key guidelines for implementing a common method for cost-benefit analysis

STATUS OF IMPLEMENTATION	ENTSO-E 1.0	ENTSO-E 2.0	ENTSO-E MARKET DESIGN (BALANCING)	SIGNIFICANTLY MORE IMPORTANT IN THE OFFSHORE CONTEXT?
INPUT(1) Project interaction must be taken into account in the project and baseline definition	One baseline (TOOT). Arbitrary clustering rules	One baseline (TOOT), an ambiguous update of the clustering	Hardly applicable but dealt with	x

INPUT(2) Data consistency and quality should be ensured	TYNDP	TYNDP	TYDNP	
INPUT(3) Costs should be reported in the disaggregated form	Not clear	Not clear	Not clear	x
CALCULATION(4) CBA should concentrate on a reduced list of effects	Reduced list	Reduced list	Reduced list	
CALCULATION(5) Distributional concerns should not be addressed in the calculation of net benefits	OK	OK	OK	
CALCULATION(6) The model used to monetize the production cost savings, and gross consumer surplus needs to be	Explicit model available	Explicit model available	Explicit model available	
CALCULATION(7) A common discount factor should be used for all projects	4 % for all	4 % for all	Uniform; aligned with TYNDP & PCI	
CALCULATION(8) A stochastic approach/scenario analysis should be used to address uncertainty	OK	The need is mentioned, but not specified how to apply the tools	OK	
OUTPUT(9) Benefits should be reported in the disaggregated form	Not clear	Not clear	Regional and country effects should be reported	x
OUTPUT(10) Ranking should be based on monetization	Multi-criteria analysis	Multi-criteria analysis, additional monetization of losses	A monetized ranking is suggested	x

The evolution of the CBA for electricity infrastructure from the 1.0 to the 2.0 version did not lead to significant progress. The CBA methodology is standing still at a time when the electricity sector is rapidly transforming especially in the offshore context effectively amounts to moving backwards (Keyaerts et al., 2016). One positive evolution in the EU energy CBA landscape is the methodology for market design, also developed by ENTSO-E. This methodology is emerging as the one which conforms most closely to the best practices identified by FSR and could serve as an example in the future.

2.3 CASE STUDIES

In this section, the analytical framework for a robust CBA method is applied to several case studies of offshore infrastructure projects. In Figure 7 (left) various offshore projects (non-exhaustive) and national frameworks for offshore grid infrastructure regimes are depicted. These projects are presented along two dimensions; the vertical dimension represents the geographical scope, going from national regimes (e.g. OFTO) or hubs (e.g. BOG), to interconnectors coupling two overseas areas (e.g. Nordlink). Along the horizontal dimension, the topology or configuration of the projects is represented, going from point-to-point connections between an offshore wind farm and the shore or between two shores to more meshed networks such as the ISLES project. Figure 7 (right) illustrates possible different grid topologies.

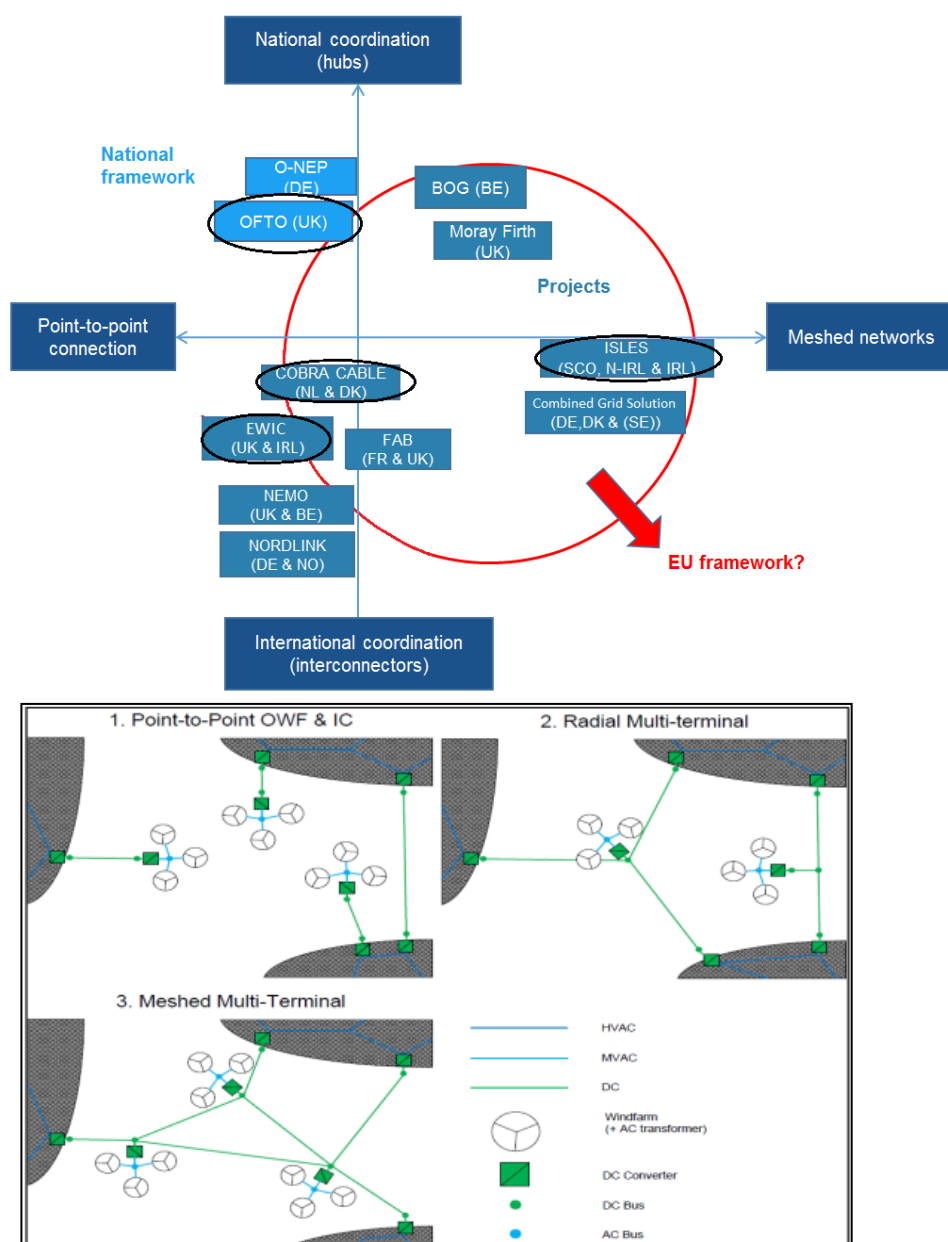


Figure 7: Presentation of case studies (national frameworks or concrete projects) along two dimensions (top) and different grid topologies (bottom). Figure on the right is taken from PROMOTiON, 2016 (deliverable 1.1).

The CBA methods applied by the promoters of the projects encircled in black are discussed in more depth in this document. CBAs of the EWIC, COBRACable and ISLES project are discussed. These three projects all received European public funding but differ in maturity and topology. The EWIC project was commissioned in 2012 and was built as a point-to-point interconnector, mainly to increase the security of supply and to allow for more integration of renewables in Ireland. The COBRACable is expected to be in operation in 2019 connecting Denmark and the Netherlands. For now, there are no definite plans to attach offshore wind generation or other offshore cables to this project, but it will be possible to do so in the future. The ISLES project is a combined solution, proposing the construction of a meshed network connecting Scotland and Ireland, while also allowing the

integration of offshore generation. The project is still in the study phase. The aim of evaluating these case studies is to critically appraise how promoters undertook the CBA for projects to be developed. Additionally, an ex-post CBA or impact analysis of the net benefits delivered by the OFTO regime is presented in Annex II.

2.3.1 CASE 1: EWIC

2.3.1.1 INTRODUCTION TO THE EWIC

In July 2006, the Irish government requested the Commission for Energy Regulation (“CER”) to arrange a competition for the construction of an East-West Interconnector (EWIC) to Britain. The interconnector would be owned and operated by EirGrid, the Irish TSO. The EWIC was described as “of critical national strategic importance” in the Irish National Development Plan 2007-2013. The main reason for the construction of the EWIC was to secure electricity supply in Ireland after ESB Power Generation announced in 2007 its intention to withdraw approximately 1,300 MW of capacity by 2010 (Eirgrid, 2006). Because of this closure, the total capacity of dispatchable energy generation in Ireland would become critical. At the same time, a lot of onshore wind farms were built in the country. By building this interconnector, the ESB could avoid curtailing wind energy production, and the resulting excess energy could be sold to Britain.

The EWIC can be classified as a shore-to-shore interconnector; neither offshore generation nor other offshore cables are connected. The HVDC cable was finally commissioned in September 2012 and runs between Deeside in north Wales and Woodland, County Meath in Ireland. Approximately 260km in length, the underground (75-km) and undersea (186-km) link has a 500 MW capacity which is enough to power 300,000 homes. ABB was awarded a contract to supply the power equipment²⁹ to connect the power grids (ABB, 2016). On the figure below a timeline of the project is shown.



Figure 8: Timeline EWIC project, we discuss the project evaluation in this document (FTI Treasury, 2013)

EWIC has been designated a “Project of European Interest” and was included in the EU Trans-European Network Energy (TEN-E) Priority Interconnection Plan, which can be regarded as one of the predecessors of the PCI program. The EU provided a total of EUR 110m support for the Ireland-UK Interconnector as part of the European

²⁹ A ±200 kV EWIC HVDC VSC Light transmission system was chosen.



economic recovery plan (EERP) to support key energy projects to help counter the effects of the financial crisis on the real economy. Also, EUR 300m in financial backing was provided by the European Investment Bank (EIB) for the construction of the cable between Ireland and Wales (European Investment Bank, 2012).

2.3.1.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR THE EWIC

This analysis is based on the business case of the East-West Interconnector published in February 2008 by EirGrid (EirGrid, 2008). It should be noted that in 2008 no CBA methodology was in place, and project promoters, such as EirGrid in this case, conducted an 'ad hoc' CBA method to apply for inclusion in the EU Trans-European Network Energy (TEN-E) Priority Interconnection Plan.

1) Considering project interaction: In the document, it is mentioned that there were at the time two interconnectors in operation on the island of Ireland. The Moyle (subsea) Interconnector (450MW), linking Northern Ireland with Scotland, and the North-South (onshore) Interconnector (330 MW) between Tandragee (N-IRL) and Louth (IRL). However, with the operation of the Single Electricity Market in Ireland, the North-South interconnector became part of the internal circuits of the new market. Additionally, in addition to the EWIC discussed in this document, it is mentioned that two further electricity interconnectors are currently proposed, a second North-South (onshore) Interconnector and a second East-West interconnector linking Ireland with the GB network in Wales. However, in the assessment of the benefits, the potential development of these two future interconnectors is entirely ignored as well as the development of other projects. In short, the CBA is solely focused on the EWIC interconnector and does not consider the positive or adverse effect of the development of other interconnector projects on its business case.

2) Data gathering process: The data collected for the assessment executed in this document is sourced from public reports from EirGrid itself and the GB TSO National Grid. These are well respected and transparent sources. In 2008, there was no TYNP yet³⁰, and thus data from the national TSOs, as a second-best option, seems like the appropriate choice to allow for comparable input for the analysis of different projects. It should be added that annual data was used for the calculation and only data from Ireland and the GB was sourced. As such, the data was very limited both in granularity as in geographical scope.

3) Disaggregated reporting of cost data: The estimated infrastructure costs are reported in a disaggregated manner and based, on a component basis, on data from two engineering companies PB Power & ESBI. The construction costs are split up into costs for the converter stations, land cables (HVDC) and marine cables (HVDC). The total capital costs are broken down in land acquisition costs, project development costs, interest during construction and Reinstatement/disturbance costs. Also, there are costs for contingencies accounted for. No cost ranges, but point estimates are given per cost component.

4) Using a common list of effects: The main benefits associated with the project are listed up as: the enhancement of security of supply, the promotion of further competition in the electricity market, environmental benefits consisting of the facilitation of a greater potential to export wind power to allow greater penetration of

³⁰ The first TYNDP was published for the period 2010-2020 in 2009 (Buijs et al., 2011).



wind sources and reduce wind curtailment, the reduced need for carrying reserve, and reduced carbon credit payments.

5) Disregard for distributional concerns: The benefit for the consumers because of an expected decrease in wholesale electricity prices is estimated per 1% of price decrease, while the benefit/loss for producers because of the market coupling with the GB market is not. However, in the final assessment, the estimated reduction in market costs for the consumers is not considered.

6) Explicit algorithms for calculating the net benefit: The assumptions made to estimate the annual benefits are clearly stated. However, it must be noted that the estimations are done very roughly; no market model combined with a network model with sufficient granularity is consulted. Because there is no detailed model used, the (potentially significant) benefit from more efficient trade because of market coupling could not be quantified.

7) Common discount factor: A weighted average cost of capital (WACC) of 5.63% (pre-tax real rate) is based on EirGrid's allowed WACC. An asset depreciation period of 30 years is accounted for. As there was no guideline for a common discount factor in 2008, this is an acceptable choice for the discount factor.

8) Dealing with uncertainty: Uncertainty in the future evolution of the system is completely disregarded. Neither a scenario analysis nor sensitivity analysis is applied.

9) Disaggregated reporting of benefits: The (quantified) benefits are reported per benefit indicator but are not geographically disaggregated. More precisely, only the benefits for Ireland are reported, no benefits for Great Britain are mentioned. This is not best practice and does not facilitate the CBCA process.

10) Final assessment of the projects: In this case study, full monetization is applied. The increase in security of supply, more precisely SoS adequacy indicator, is monetized using the 'Additional adequacy margin' approach (ENTSO-E, 2016a). This approach exists out of measuring the spare capacity (in MW) that does not need to be installed as a result of expanding transmission capacity. That capacity is then multiplied by the investment cost (in €/MW) of a peaking unit. An important assumption when applying this approach is that the peak demand in both countries connected by the interconnector is not very correlated. As no detailed market and network model is applied, the Expected Energy Not Served (EENS) is not calculated, and as such, the problem of determining a Value of Lost Load (VOLL) is omitted.

Additionally, the value from reduced wind curtailment (modelled by the extent to which wind would have to be curtailed in both the presence and the absence of the electricity interconnector) reduced need for carrying reserves (based on the value for this indicator for the Moyle interconnector). The reduced carbon credit payments (based on the estimated reduction in emission multiplied by the estimated price for carbon emissions in €/ton) are monetized.



2.3.1.3 DISCUSSION ON THE EWIC CBA

A) This case study, although conducted in 2008, follows some guidelines of the analytical framework which are not addressed by ENTSO-E's CBA 1.0 and 2.0. Examples are full monetization and the disaggregated reporting of costs. However, regarding other guidelines this case study does not agree with the framework, most notably considering project interaction, addressing uncertainty and geographically disaggregated reporting of benefits. Also, the model applied is deemed very simplistic.

B) Security of supply and the integration of renewables are promoted as the main benefit of this interconnector. These benefits are also monetized. It is surprising that next to these benefits, the revenues obtained by the interconnector due to explicit auctions for the reserved capacity of the cable or implicitly due to congestion and price differentials in the Irish and GB market is not estimated. This auction revenue could add significant value to interconnector.

2.3.2 CASE 2: COBRACABLE

2.3.2.1 INTRODUCTION TO THE COBRACABLE

COBRACable is a planned 325km long subsea interconnector between Denmark and Netherlands. The ownership of this subsea cable is shared by Dutch TSO TenneT and the Danish TSO Energinet. It is expected to be in operation in 2019 with a designated capacity of 700MW. The interconnector adopts a Tee-in topology where the wind farm is envisioned to be directly connected to the interconnector cable. This feature is mainly driven by the need for power trade between connecting countries with the main advantage of achieving cost reduction at system level since it shortens the total subsea cable length. This project is motivated by four long-term objectives: 1) To facilitate the transport of renewable energy; 2) To form a crucial part of a strong, interconnected European electricity grid; 3) To enhance security of supply in the Northwest European electricity market; 4) To enhance the level playing field in the internal European electricity market.

As far as the regulatory facilitation at European level is concerned, the COBRACable has acquired the Project of Common Interest (PCI) status; it was listed both on the 2013as on the 2015 PCI list. As a result, COBRACable should receive favourable and rapid regulatory treatment at the national level. For the financing support from the European level, the project has received 86.5 M€ EEPR grant, and this grant action is extended to December 2017. It is interesting to see that this grant was awarded as even without the subsidy the estimated NPV of the project is positive. The main motivation for awarding the financial support relates to the possibility of connecting new offshore wind farms to the cable as the first step towards a meshed North Sea offshore grid. Incentivizing anticipatory investment as in this case study is regarded as best practice.

2.3.2.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR THE COBRACABLE

This assessment is based on the business description of the development of the COBRACable published on 3 December 2013 by TenneT (TenneT, 2013). In 2013, the ENTSO-E CBA 1.0 methodology had not yet been approved by the European Commission, as such also this document could be seen as 'ad hoc' CBA.



1) Considering project interaction: Since COBRACable is the first planned interconnector linking Netherlands and Denmark, and there is currently no other interconnection planned for these two countries, the cost and benefit calculation of COBRA is not clustered with other new investment projects. Even if there were other new investment projects, there would most likely be no argument for clustering, because the projects would probably be in competition with each other.

One reference grid or baseline, shown in Figure 9 below, is applied to the calculations of the socio-economic value of the COBRACable. This reference was built up by data from the three TSO's data for Denmark, the Netherlands, and Germany. Data for the other countries are taken from extensive work done by Energinet. The sources of that work are ENTSO-E's regional groups, national plans from different countries and bilateral studies. The outcome of a CBA is very sensitive to the reference grid applied. In this case study, it can be seen that a thorough analysis was done to assess the future interconnection capacities. However, the sensitivity of the CBA output to the construction (or not) of other projects to flag positive or negative synergies was not conducted. For example, on the 2015 PCI list, also the "Viking Link" (PCI 1.14) between Denmark and the UK is listed. At the time this analysis was done, in 2013, it could not be known that this new link would be promoted. However, the impact of this link on the CBA of the COBRACable can be expected to be significant. By applying a regional planning approach, which would allow for a better forecast of the future grid, these uncertainties could be mitigated and a more robust assessment could be conducted.

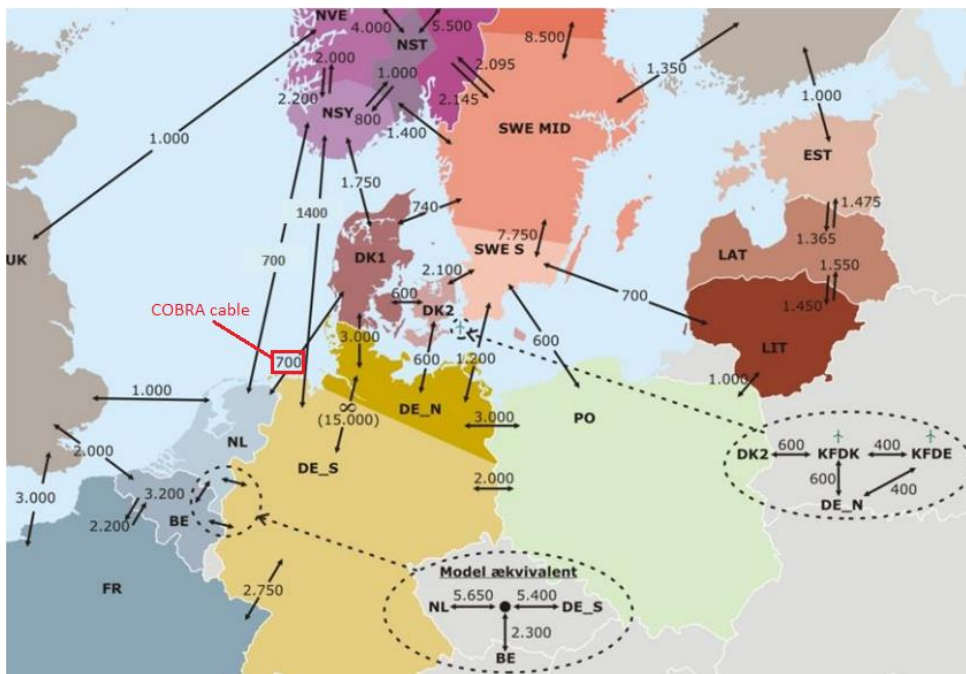


Figure 9: Reference grid applied in the COBRA business case, assumed interconnection capacities for 2030

In the analysis, the reduction of congestion revenue on other interconnectors of the two connecting countries and of the European system in the timeframe between 2018 and 2058 is considered. As such, the interaction of COBRA and these projects are taken into account.

2) Data gathering process: The calculations contained in the assessed business case are based on results from the *Yearly Economic Update 2013* (Energinet.dk, 2013). The reference scenario is set up by TenneT NL, TenneT DE, and Energinet. Data has come from bilateral studies of TenneT and Energinet as well as ENTSO-E. The 2011 International Energy Agency expected fuel price is used in the reference scenario.

3) Disaggregated reporting of cost data: The estimated investment cost of the COBRACable is segmented into these components: COBRA automation, COBRA land cable, COBRA sea cable, COBRA DC converter, COBRA civil works, COBRA licensing, COBRA project cost, CAR and contingency PM. The uncertainty of total cost is reported with two probability intervals, however, per cost component, there are only point estimates based on the experience and indicators from TenneT and Energinet. These costs are calculated on the annual base from 2014 to 2019 when the project is expected to be built.

4) Using a common list of effects: The main quantified benefit indicators of the project are: the value of environmental sensibility, technical resilience, flexibility, non-curtailed RES, reduced CO₂ emissions, increased security of supply, socioeconomic value and auction revenues. On the cost side, reduced congestion rents, losses, OPEX and investment cost are listed.

Also, the benefits of COBRACable with respect to CO₂ reduction and system overload reduction as an indicator for system integration of renewable energy are presented in Germany, Netherlands, and Denmark. The effect on the security of supply is assessed qualitatively. The preliminary TYNDP 2014 results for the reduction of losses as well as technical resilience and system flexibility is also used in the COBRA CBA.

5) Disregard distributional concerns: The benefit for the consumers because of an expected decrease in wholesale electricity prices is estimated per 1% of price decrease, while the benefit/loss for producers because of the market coupling with the GB market is not. However, in the final assessment, the estimated reduction in market costs for the consumers is not considered.

6) Explicit algorithms for calculating the net benefit: The presented business case is based on an analysis conducted in 2013 by Energinet. The BID-model was applied in the study by Energinet. Some of the underlying assumptions are described in the assessed document, but the explicit algorithm is not discussed. ENTSO-E (ENTSO-E, 2014b) described the BID- model as a fundamental model that estimates the price by calculating the intersections between supply and demand. The model has a regional structure with specified transmission capacity and trading regime between the regions. For each region, there are specified demand curves with some price elasticity for some consumer groups. The supply curve is constructed as a merit order curve defined by production capacities and short-term marginal costs.



Model calculations were made for 2018, 2023 and 2030. The value of intervening years was investigated through linear interpolation. The annual costs and benefits after 2030 were assumed to remain unchanged with respect to the values for 2030.

7) Common discount factor: The discount rate of 4% as recommended by ACER is adopted for the net present value calculation of the COBRA business case. Sensitivity analysis is performed with the discount rate at 3.6% and 5%. The technical lifespan of 40 years is assumed to calculate the expected revenue.

8) Dealing with uncertainty: Uncertainties are addressed both in the cost and in the benefit computation. On the cost side, sensitivity analyses are performed for the COBRA investment costs. The investment cost estimation varies between 540 million and 621 million with the expected investment cost to be 577 million.

Two previous studies were conducted³¹ for the COBRACable, and these assumed two scenarios: New Stronghold and Green Revolution. The New Stronghold scenario assumes that the generation mix mainly consists of conventional generation in 2030, while the Green Revolution includes more wind and solar energy in the generation mix. The reference scenario, applied in this case study, occupies a mid-point between New Stronghold and the Green Revolution. No scenario analysis was applied in this case study, but the result of the study by the Brattle Group (Brattle Group, 2011) is seen as a suitable reference for comparison and could be seen a substitute for scenario analysis.

As already mentioned in point 8), the sensitivity of the outcome of the case study to 2 other discount factors (next to the recommended 4 % by ACER) is reported.

9) Disaggregated reporting of benefits: The welfare impact split up between producer and consumer surplus. It is reported in three countries: the Netherlands, Denmark, and Germany. For these three countries, quantified benefits are computed for each benefit indicator. Quantitative benefit indicators in each geographical area include: 1) value of environmental sensibility, the value of technical resilience, the value of flexibility, the value of non-curtailed RES, the value of reduced CO2 emissions, the value of increased security of supply, socioeconomic value. Specifically, for Germany, also the reduction of re-dispatch cost is calculated.

10) Final assessment of the projects: In this case study, project benefit is partially monetized. However, a final NPV value of the project is put forward as the outcome of the analysis. The main monetized benefits include the socio-economic value and auction revenues. It is unclear if externalities such as the reduction in CO2 emissions are internalised in the socio-economic value.

For the security of supply, only a qualitative assessment has been made with the argument that the three involved countries have current supply rates at 99.99% and that therefore an additional 700 MW does not significantly

³¹ In 2010 the business case for COBRACable has been assessed by Pöyry, (2010) and in 2011 a re-assessment was done by the Brattle Group, (2011)

improve the security of supply. As for effect on reduced CO₂ emissions, reduced overload due to RES and reduced losses, the former is reported in units ktons/year, the latter two in GWh/year.

2.3.2.3 DISCUSSION ON CORBACABLE CBA

A) Although the case study was performed before the ENTSO-E CBA 1.0 (ENTSO-E, 2015a) was approved by the European Commission, it seems certain elements coming back in that methodology were applied. Examples are the data gathering process, the discount factor and the reduced list of effects. Overall the case study is performing well.

B) An adequate reference grid was applied. However, the sensitivity to the development of other projects was not investigated. This seems to be a critical issue, and it is understandable that a project promoter, such as a TSO in this case study, does not have sufficient information to perform this task by itself.

C) Full monetization is not applied. However, as an increase in security of supply was not one of the main benefits of the projects and the estimated monetized benefits (mainly auction revenues and socio-economic benefits) were sufficient to cover the cost estimates, the outcome of the analysis, an NPV based on partial monetization, seems appropriate.

D) It is interesting to see that a significant EU grant was awarded, conditional on the choice of a certain converter technology, namely VSC. By opting for VSC technology, there is the possibility to connect new offshore wind farms to the cable as the first step towards a meshed North Sea offshore grid. Incentivizing anticipatory investment as in this case study is regarded as best practice.

2.3.3 CASE 3: ISLES³²

2.3.3.1 INTRODUCTION TO ISLES

The Irish-Scottish Links on Energy Study (ISLES) is a tripartite collaboration between the Governments of Republic of Ireland, Northern Ireland, and Scotland. Its aim is to enable the development of market to market interconnected grid networks to enhance the integration of renewable energy between the countries. The European INTERREG IVA Programme provides part of the funds for the project. In total, the project received two funding rounds to conduct scoping studies. The ISLES project represents a combined solution, and both integrates significant offshore renewable generation located in the Irish Sea and the Atlantic Ocean off the coasts of Ireland and Scotland, and connects the GB and Irish electricity markets (all-island Irish Single Electricity Market (SEM)). Given the surplus of generation requirements in Ireland that the proposed project would deliver, the core value adds of assets modelled in ISLES are to provide interconnection with mainland Great Britain, and thereafter the wider EU allowing for a pathway to reduced electricity prices, and to relieve constraints on the Irish grid.

³² The subsequent analysis was primarily a result of desk-based research. However, applicable consultants and public civil servants were engaged for their input. More precisely, high-level conversations were held with Scottish Government, Pöyry UK and Baringa Partners LLP to clarify the steps undertaken for the analysis.



The first project phase, ISLES I, consisted of a feasibility study including a CBA that was commissioned in 2010 and published in 2012. In 2013 ISLES II was launched. This included three additional work streams, 1) a spatial plan, 2) regulatory model, and 3) business plan. All ISLES II reports were released in 2015. It should be noted that both the 2012 and 2015 analysis was carried out by external consultants³³. Figure 10 presents the map of the ISLES Zone and illustrative configuration in 2030.

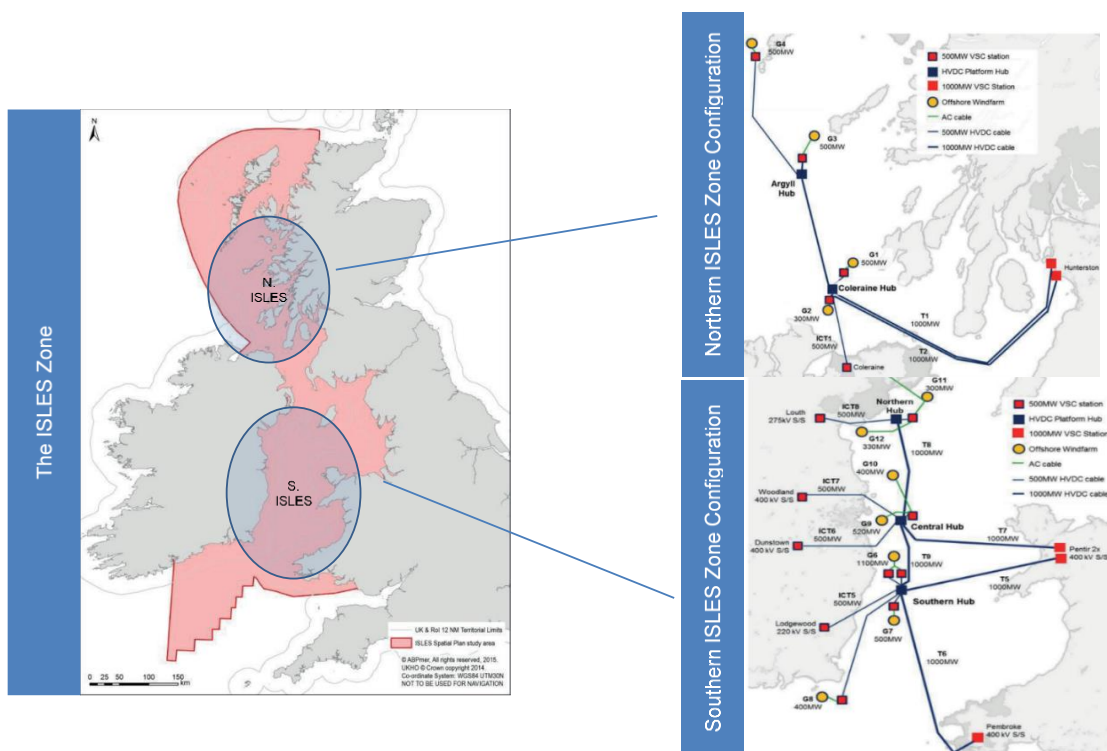


Figure 10: Overview of ISLES Zone map and illustrative configuration in 2030 (ISLES, 2015a)

Within the 2012 report, two ISLES concepts were developed, a Northern ISLES concept with 2.3GW of generation and 500 MW of firm interconnection capacity, and a Southern ISLES concept, consisting of 3.4GW of generation and up to 2 GW of interconnection capacity to test the sensitivity of certain key parameters. Both of the ISLES concept areas were classified as PCIs in this first list (ISLES, 2015d). Projects must re-apply under each update to the list and comply with reporting obligations to remain a PCI and the second PCI list, published in 2015; only the Northern ISLES concept was included (EC, 2016b).

The 2012 analysis included a partial cost-benefit analysis within the *Economic and Business Case Report*. The opportunity was further expanded with the release of the ISLES II documentation in 2015. Specifically, the *Business Plan* and the *Network Regulation and Market Alignment Study* contributed towards qualitative and quantitative cost and benefit analysis.³⁴ It is understood that the CBA document and data used to gain PCI

³³ See <http://www.islesproject.eu/> for more information.

³⁴ The ISLES CBA related documents are available in (ISLES, 2015a, 2015b, 2012). Note, the (ISLES, 2015b) was not reviewed here due to its qualitative nature. However, it includes some important considerations, which help to frame the 2015 quantitative analysis.

approval and status in the first list was derived from the 2012 report. Therefore, it is the primary document assessed. However, the 2015 document has also been reviewed. A dedicated qualitative assessment was produced in 2015, but this was not examined within this exercise.

It should be noted that due to the conceptual nature of the study and the limited development of the ISLES site, both the 2012 and 2015 studies are formulated more as proof of concept documents with some CBA, rather than being fully aligned to typical market CBAs and the ENTSO-E guidelines. Therefore, while reviewing these documents against the proposed guidelines, it quickly became apparent that these diverged from what would be required in a CBA to cross-compare pan-European benefit relative to other proposed PCIs. An overarching recommendation is, therefore, to promote as far as possible the need for a discrete CBA study that is aligned to the suggestions in this report that is separate from the wider package of proof of concept/development packages.

Further complicating this assessment, the two pieces of analysis differed in approach, making comparability between them difficult. The 2015 analysis summarises this as “Compared to the analysis in ISLES I, which focused on presenting a single set of average results for the complete set of generation and network assets in the ISLES zone, the analysis in this report is focused much more on analysing and presenting the costs and benefits associated with each incremental investment decision in generation and network assets”.

There are benefits and weaknesses to both pieces of analysis, but, overall, they both fall short of expectations laid out within this document. For example, the 2012 analysis does not apply the same rigour in its use of scenarios and market modelling as the 2015 analysis. However, it more clearly lays out the data inputs. Due to the multi-stakeholder and cross-jurisdictional nature, both pieces of analysis highlight upfront the difficulty of modelling different regulatory arrangements and incentives on the development of generation sites and networks across ISLES. As such these studies also seek to provide insight into different regulatory arrangements that could provide the right incentives to maximise social welfare. The combined analysis suggests many of the ISLES sub-projects are simply not viable as standalone projects, but require the ISLES system as a whole to be installed to become commercially viable (for example due to reduced transmission costs). The importance of forward planning and regulatory considerations is suggested. For instance, it may make sense for a single offshore transmission owner to oversee the meshed network. However, these should be secondary considerations and only explored once the overall net benefit has been established.

2.3.3.2 THE ASSESSMENT OF THE CBA CONDUCTED FOR ISLES

1) Considering project interaction: Neither piece of analysis explores the interaction of the ISLES PCI relative to other proposed PCIs, nor do they explicitly examine the development of discrete projects such as ‘Greenwire’ a proposed generator-to-market interconnector between the UK and Ireland.³⁵ Instead, they focus to a greater

³⁵ The Greenwire project has since evolved into the Greenlink interconnector project. For more information on the development of the Greenwire and Greenlink project see Dutton, (2016). ‘The politics of cross-border electricity market interconnection: the UK, Ireland and Greenlink’. The 2015 counterfactual ‘No ISLES’ does make reference to a ‘new standalone 500MW interconnector between GB and Ireland which would match the Greenlink characteristics, but it is not mentioned by name.



extent on the interaction between different sub-ISLES configurations developed by the consultants (explained in greater detail below). Ideally, in the first instance, different ISLES configurations could be examined to determine the configuration with the greatest welfare benefits. Thereafter this configuration would then be cross-examined against the wider EU PCIs.

Within the 2012 report, projects were clustered in a Northern and Southern ISLES concept according to the consultant's expertise and analysis, and consultation with stakeholders. The Northern cluster was used to test the ISLES thesis and apply baseline analysis and the Southern ISLES concept to test the sensitivity of certain key parameters. The 2012 CBA is relatively unclear in its overarching counterfactual. Limited comparison (monetised) is available between project clusters (i.e. north and south) and against the discrete UK Round 3 wind farms outside of the ISLES zone. Importantly, the analysis does not appear to value welfare benefits against the UK, Irish SEM or wider EU markets, i.e. evolution of these markets with and without ISLES, nor does it appear to consider other projects of common interest (PCIs) within scenarios.

The 2015 analysis improves upon this aspect, in that it is more explicit in its approach and applies two scenarios –(All) ISLES and No ISLES.³⁶ In addition, it separately lays out 10 offshore wind projects across Northern and Southern ISLES zones within an illustrative scenario.³⁷ For each of these, it seeks to see the effect on GB and Irish markets with and without ISLES, but does not consider pan-European interaction. It suggests the impact of coordinated generation is more important for the northern cluster and that benefits are likely to accrue for the Irish SEM. The overall configuration explored in ISLES I is similar to ISLES II, with some minor modifications.³⁸

2) Data gathering process: The assumptions used within the 2012 model are qualitatively and quantitatively laid out, along with the key sensitivities. The rationale for the choice of assumptions is discussed as appropriate. Data was not derived from a common data set, but instead, a mix of geographically appropriate and publicly available sources was used. While the 2012 study did for the large part provide clear assumptions, the data was acquired from a diverse number of sources, some of which were not referenced. The document suggests a comparison with other data sources was conducted and preference is given to sources where core numbers were clearly referenced (although there was no further clarity on the other sources). There was no evidence that stakeholders were given the opportunity to propose or challenge numbers. The 2015 analysis is even less clear in its data gathering process as it largely uses a proprietary model and in-house data sets (although some limited information is available in the appendix).

The choice between a common data set and locally appropriate data presents a trade-off between comparability and accuracy. For projects similar to ISLES, where the exercise is theoretical, and developers are notably absent, common data sets would be highly beneficial. Consultants could then apply regional data sets to tailor analysis to specific items (e.g. prices for construction and operation).

³⁶ In the (all) ISLES scenario both the development of the Northern and Southern clusters are assumed, however the benefits of each cluster is reported separately.

³⁷ Note: the analysis makes separate references to 10 and 12 offshore wind projects within the illustrative scenario.

³⁸ The 2015 document states that in coordination with the ISLES steering committee a wind farm in the west area of the Northern ISLES zone was removed from the analysis when compared to ISLES I.

3) Disaggregated reporting of cost data: Across the 2012 analysis there is a mixed level of disaggregation. In the 2012 study, key inputs are provided and referenced. Some aspects are presented in granular detail, but not all (for instance CAPEX is provided as a gross sum, and not broken down into the sub-components). The comparison would, therefore, be largely available with a future ACER database, although it would require some work to extract the data as this is found in the entire document. The analysis would benefit from a dedicated appendix with full disclosure of data and sources provided in a tabular format (not just key inputs) to allow for easy comparison. The 2015 analysis was less systematic in its provision of cost data. However, some aspects were improved such as within ISLES I a single unit generation cost (£/MW) was applied to all ISLES generation sites, while in the ISLES II analysis these were tailored to water depth and distance to shore. In most cases, single data costs are provided, i.e. a range of possible costs / future costs are not provided.

4) Using a common list of effects: Both studies go beyond the suggested reduced list of effects making comparability of the key issues difficult. The 2012 analysis examines several areas beyond the suggested reduced list. Items examined included:

- (i) ISLES network viability (revenues and costs);
- (ii) Conventional generation displacement and cost impact;
- (iii) Fuel burn reduction and the associated reduction in CO₂ emissions;
- (iv) Viability (i.e. revenue and costs) of an offshore grid for the connection of renewable energy;
- (v) Benefits to networks such as reduction of system operating costs, and security of supply;
- (vi) The financial impact on end users;
- (vii) Indicative network charges under practicable regulatory regimes;
- (viii) Financial viability of the entity providing offshore grid; and
- (ix) Overall socio-economic benefit (GVA, direct and indirect jobs).

In addition, the analysis provides a deeper dive into the level of renewable subsidies required; transmission pricing; interconnection (including spinning reserve, system security, restrictions, pricing); network optimisation; the impact of network availability; financing and bankability; and comparison with alternatives.

The 2015 analysis is more aligned to a reduced list of effects. For example, it correctly omits analysis on jobs and supply chain benefits, seabed leasing revenue, and tax benefits. However, it still covers a wide number of areas by applying analysis on network cost savings to generation from connecting to multiple use networks; increased network reliability; access to low cost European funding; project risk; commercial value of increased capacity between Irish and British markets; and wider impacts (including average wholesale electricity prices; displaced cost of fossil fuel generation; CO₂ emissions; reduced number of starts for fossil fuel generation; capture prices). As per the overarching recommendations, this piece of analysis could have been improved by focusing on a reduced list of effects that would allow greater cross comparability with other PCIs. For example, specifics on the financial viability of the entity providing the grid, access to finance, impact on end users, indicative network charges, financial viability, distribution concerns, subsidy level reduction and socio-economic benefit should be in a separate and subsequent analysis. These factors are difficult and at times contentious to calculate and should

be examined only once EU-wide benefit through a CBA has been established. The aim is to assess whether the overall project has a net benefit regardless who wins and who loses.

5) Disregard distributional concerns: The 2012 and 2015 analyses both include some level of distributional concerns, i.e. they highlight the economic benefits between countries and/or between consumers and producers. Indeed, it explicitly states that “the quantitative analysis is used to explore the distribution of costs and benefits of several types of coordination.” However, no different weights are given to benefits or costs for certain countries or agents, which can be regarded as best practice.

6) Explicit algorithms for calculating the net benefit: The explicit calculations are not made available, neither are the models available to test the assumptions. However, both pieces of analysis are clear in approach, models applied and aspects examined. This is summarised below.

The 2012 modelling took a multi-stage approach. First, an overview model³⁹ analysing financial flows was run to determine which input assumptions had the most sensitivity to and impact on outputs, and to rank these accordingly. These were then applied in the detailed model. The overview model was also used to explore indirect impacts initially, and a comparison of ISLES with other similar UK offshore projects was made. The analysis uses as its cost base the spot year of 2020 (as this is deemed the earliest date when the Northern ISLES would be connected). From this point on, costs evolve according to defined inputs (e.g. fuel costs).

This overview model included the impact of intermittency renewables on system operating costs and CO₂ emissions as a result of the need for part loading and fast reserve requirements on conventional generation. Other aspects that were examined included: energy/demand forecasts; fuel price forecasts; dispatch models based on load duration curve; chronological models (half hourly demand and wind output data); new entry evaluation; financial overview; system security; and overall project costs and revenues. In addition, a full NPV cost-benefit model was developed, built around the Northern ISLES concept using discounted cash flow analysis from 2010 to 2035. This incorporates time-dependent forecasts for key input variables and captures flows of direct project revenues and costs.

The 2015 analysis aligns with the UK regulator’s approach to impact assessments for proposals of the Integrated Transmission Planning Regime (ITPR), by examining where coordination is socially beneficial. The costs and benefits are the results of the numerical project and wholesale modelling analysis. Specifically, two models are applied. A generation and transmission project cost model built for the CBA analysis, and Pöyry’s proprietary wholesale electricity model (BID3). This analysis included relevant European countries (France, Belgium, Netherlands, Denmark, Germany, and Norway) modelling the hourly dispatch of plants to minimise costs for Europe. Specifically, spot years were modelled to assess the development and operation of ISLES (2022, 2023, 2025, 2027, 2030, and 2035). Outputs are electricity prices, generation and revenue of the plant, arbitrage revenue for interconnectors, the total cost of generation, and CO₂ emissions.

³⁹ Leaning upon, energy / demand forecasts, fuel price forecasts, a dispatch model based on load curve duration, and a chronological model – half hourly demand and wind output data.



7) Common discount factor: In the 2012 analysis, a 2% discount rate was applied to cash flows out to 2035. This differs quite substantially with the proposed 4% discount rate, and the 3.5% discount rate mandated in the UK Treasury's Green Book.⁴⁰ The 2015 analysis does not provide the discount rate used; this makes a cross-comparison of end results between the two ISLES analyses and with other PCIs very difficult.

8) Dealing with uncertainty: Overall it is unclear how the CBA dealt with uncertainty. Both the 2012 and 2015 analysis highlight the inherent uncertainty with the ISLES analysis. However, they do not appear to use TYNDP scenarios to negate this. To counteract uncertainty, public references are used for items such as carbon emissions, fuel prices, and energy demand. In addition, sensitivity analysis is conducted. The 2015 analysis suggests the proprietary model features stochastic dynamic pricing of hydro dispatch to quantify the role of intermittency in the EU electricity markets and the role of flexibility. However, it is not clear the extent to which this was used for the ISLES analysis.

9) Disaggregated reporting of benefits: The 2012 analysis examines the costs and benefits to the generators, owner of the offshore grid, onshore network owner, system operators, impacts upon conventional power plants, and the impact on energy users. However, in terms of the country to country distribution, it only qualitatively suggests there may be a greater benefit to Ireland and Northern Ireland. It states that for England and Wales the ISLES proposition would only be attractive if the energy derived from ISLES was cheaper than that of other projects under consideration.

The 2015 analysis specifically examines the distribution of costs and benefits that accrue to the individual projects within ISLES versus the wider benefits. In addition, it examines a number of metrics (e.g. capacity market revenues, arbitrage revenue, and wholesale price impact) the distribution of these between Ireland and Great Britain.

The benefits of coordination under three areas are examined, which does place emphasis on geographical distribution between Irish versus GB benefits. Reported benefits included are presented in Figure 11 below.

Direct benefits for the delivery of a project	Wider (monetised) energy sector benefits	Support for wider policy goals
Lower offshore network CAPEX Increased reliability Lower cost of funding	Market to market capacity Onshore Transmission benefits Optionality for future generation development	More integrated European electricity market Supply chain New generation technologies Environmental goals

Figure 11: ISLES II: Different types of benefits that may arise from allowing multiple uses of offshore transmission network assets in the ISLES Zone

10) Final assessment of the projects: As previously highlighted, these studies are formulated principally as proof of concept documents rather than full CBAs and do not present a single NPV value for the entire ISLES project. This limits comparability with other PCIs. Across both analyses, the final assessment of the project is laid

⁴⁰ See for example: www.gov.uk/government/uploads/system/uploads/attachment_data/file/220541/green_book_complete.pdf

out based on both monetized and qualitative benefits across several areas. Ideally, these should have been separated and ranked accordingly.

In the 2012 analysis, monetized aspects include subsidy levels and potential subsidy savings, and CAPEX. Non-monetised aspects include CO₂ emissions saved, as well as considerations of network availability, lower capital costs, and interconnection benefits. A single aggregated per annum saving is provided for the southern ISLES, but it is unclear how this was built up. The 2015 analysis provides in-depth analysis, both quantitative and qualitative in regard to aspects highlighted in point 9. However, there is a limited attempt to provide a single net benefit or cost number. Overall both studies highlight the strong uncertainties and limited benefit of the ISLES project. However, they do mention the benefit from coordination which could make marginal generation projects viable.

2.3.3.3 DISCUSSION ON ISLES CBA FOR CONSIDERATION

A) Overall the evaluation of CBA method applied in the discussed ISLES business cases is not positive in the context of the PCI selection procedure. Instead of a common CBA, a more tailored-made analysis was performed, making it hard to compare the benefits and costs of the proposed projects with other PCI or electricity infrastructure projects. There are some important challenges when conducting CBA's for complex offshore meshed grids projects with multiple permutations in design such as ISLES.

It is important to note that the ISLES project is conceptual in its design, with many projects in the pipeline having fallen through, although key anchor projects remain. This CBA is particularly uncertain given that it has been led by the Government, without the inclusion of developers who are actively seeking to develop these sites. Determining the economic viability was said to be very challenging given a large number of possible interconnection design configurations, radial links, renewable generation options, and stakeholders in play. The ISLES 2012 study, therefore, mentioned the need to “strike a balance between depths of analysis on issues which have high materiality to the potential ISLES business case, without straying too far into much larger policy issues which are marginal to the central question of the viability of ISLES.”

B) In the case of multiple potential topologies, it is suggested that a clear choice be made for a small discrete number of configurations and an independent CBA performed for each topology. This to avoid mixing up studies assessing the optimal topologies and a CBA of the project (with a particular topology) in the EU context.

C) CBAs are commonly undertaken for single projects (e.g. a single interconnector), which will be developed by the market. The case for multi-use interconnection is more complicated, with inclusions of offshore generation sites that may not be economically viable otherwise. Combined solutions, including both the connection of offshore wind farms and interconnectors, are by definition a cluster of projects and therefore their assessment is highly dependent on the degree to which they are allowed to be evaluated as clusters. In ENTSO-E CBA 2.0 ((ENTSO-E, 2016a) projects can be clustered if their development is at maximum one 'maturity stage'⁴¹ apart from the main

⁴¹Five maturity stages are defined: under consideration, planned, design, permitting and under construction.

project and if they are necessary to reach the full potential of the main project. This rule leaves ample room for interpretation as described in the previous section. Additionally, there will be a need for simplified rules for “de-cluttering” benefits calculated at cluster level as also described in Annex II of ACER, (2017).

D) The development of ISLES will only make sense if generation resources can be connected more cost-effectively or more rapidly than other offshore projects. Interconnection may have wider benefits. In addition, such benefits may only arise under strict circumstances. Properly accounting for the benefits of providing interconnection capacity between markets and connection generation to shore, while avoiding double counting, is more complicated in the combined solution case. It is suggested that guidance is provided on how to approach this modelling difficulty.

2.3.4 OVERVIEW OF THE CASE STUDIES

Table 2 gives an overview of the assessment of the case studies using the analytical framework. The dimensions which do not comply completely with the analytical framework are highlighted in orange and the dimensions strongly disagreeing with the identified best practices are highlighted in red.

Table 2: Summarizing table of the assessed case studies

	EWIC (IRL-UK)	COBRACABLE (NL-DK)	ISLES (SCO-IRL- N-IRL)	
Phase	Commissioned in September 2012	Final investment decision taken, expected to be in operation by 2019	In the study phase	The concern in the ENTSO-E 1.0 and 2.0 methodology
EU funding	“Project of European Interest,” included in (TEN-E) Priority Interconnection Plan. Received significant EEPF funding (110 m€)	On the 2013 and 2015 PCI list. EEPF funding received/allocated for studies and construction (86.5 m€)	On the 2013 and 2015 PCI list. The EU INTERREG IVa Program funded 1.6 m€ for ISLES I one and 0.9 m€ for ISLES II	
INPUT(1) Project interaction must be taken into account in the project and baseline definition	No project interaction is taken into account	TOOT approach is applied, and the change in congestion rent of other interconnectors is calculated	No interaction with other PCI projects is taken into account. The interaction between ISLES clusters is analysed partially.	Critical
INPUT(2) Data consistency and quality should be ensured	Ok	Ok	No TYNDP by local data is utilised although from respected sources.	/
INPUT(3) Costs should be reported in the disaggregated form	Ok	Ok	Ok	Harmonisation needed
CALCULATION(4) CBA should concentrate on a reduced list of effects	Ok	Ok	Ok for the 2015 analysis. However, not the ENTSO-E CBA 1.0. list is applied.	/
CALCULATION(5) Distributional concerns should not be addressed in the calculation of net benefits	Ok	Ok	Ok	/

CALCULATION(6) The model used to monetize the production cost savings, and gross consumer surplus needs to be explicitly stated	Explicitly stated but the not detailed market and network model used	Ok, explicitly stated and detailed market and network model are used (details are not public)	Ok, explicitly stated and detailed market and network model are used	/
CALCULATION(7) A common discount factor should be used for all projects	Ok, there was no common discount factor determined thus the allowed WACC of EirGrid was used	Ok	A very low discount factor is applied in the 2012 analysis (2%) ,and no value is provided in the 2015 analysis	/
CALCULATION(8) A stochastic approach/scenario analysis should be used to address uncertainty	Uncertainty is disregarded, no scenario or sensitivity analysis applied	Ok, 2 scenarios are applied plus sensitivity analysis by varying total cost and discount factor	Scenario and sensitivity analysis is applied, although not using the TYNDP scenarios.	/
OUTPUT(9) Benefits should be reported in a disaggregated form	Only the benefits for Ireland are considered	Ok, benefits are reported disaggregated	Ok, benefits are reported disaggregated	Ok
OUTPUT(10) Ranking should be based on monetization	Ok, full monetization is applied	Partial monetization is applied, but a final NPV value of the project is underlined. Additional indicators in non-monetary metrics are mentioned more for informational purposes	Both quantitative as qualitative cost and benefit indicators are reported. No full monetization is conducted.	Harmonisation needed

2.4 CONCLUSION AND RECOMMENDATIONS

The application of cost-benefit analysis (CBA) for offshore electricity infrastructure projects with a pan-European impact is discussed in this document. When investigating the planning of a future meshed offshore grid covering the North Sea, it is relevant to look at how the economic assessment of individual smaller-scale offshore infrastructure projects is done, as it is likely that developers will concentrate in the short to medium term on such projects. Then, in the longer-term, an offshore meshed network could be created gradually by linking these individual projects together (Woolley, 2013b).

In this document, firstly a framework for a robust CBA method is presented. Using this framework, the CBA methodologies (ENTSO-E, 2016a, 2015a, 2015b) published by ENTSO-E are assessed. These methodologies are evaluated as they serve as a guideline for the CBA conducted by project promoters of energy infrastructure with a pan-European impact, including offshore electricity transmission projects, to obtain a PCI status.⁴² Further, the framework is applied to three case studies of offshore infrastructure projects. All these projects received European public funding but differ in maturity and topology. Three projects namely EWIC, COBRACable and ISLES, were evaluated in this chapter. The EWIC project was commissioned in 2012 and was built as a point-to-point interconnector, mainly to increase the security of supply and to allow more renewable integration in Ireland. The COBRACable is expected to be in operation in 2019 connecting Denmark and the Netherlands. For now, there are no concrete plans to attach offshore wind generation or other offshore cables to this project, but there is the possibility to do so in the future. The choice for a technology that allows for the integration of the COBRACable in a future offshore (meshed) grid was required, in order to obtain significant European public funding. The ISLES project is a combined solution, proposing the construction of a meshed network connecting

⁴² For more information about Projects of Common Interest, please consult the textbox in the introduction.

Scotland and Ireland, while also allowing the integration of offshore generation. The project is still in the study phase.

Three key issues were identified after assessing the ENTSO-E CBA 1.0 and 2.0 methodology. Firstly, the coordination among different EU electricity infrastructure projects is not adequately supported by the ENTSO-E methodology. The ENTSO-E methodology recommends the use of at least one baseline or single reference grid that represents the expected future network for the assessment. However, by applying only one reference grid, positive or negative synergies between different transmission projects cannot be easily identified. Also, clustering rules remain open to interpretation. This coordination issue is especially relevant for offshore infrastructure projects as an offshore grid in the North Sea would be built up almost from scratch. This implies that the outcome of the CBA analysis of individual offshore energy infrastructure projects, serving as future links creating in the longer term an offshore grid, is expected to be highly interdependent.

When looking at the case studies, it is established that this coordination issue is critical. The assessment of the EWIC cable completely ignores other offshore projects potentially to be developed. Also in the ISLES case study, the interaction between the ISLES project and other PCIs is not investigated. In the business case of the COBRACable the minimum standard required by ENTSO-E, namely the application of one future reference grid, is followed.

Recommendation 1: dealing with interactions between (offshore) PCIs

Improve project clustering and baseline definition in the common CBA methods: ACER could require that quantitative evidence complements the qualitative rule for clustering and it could also require that a method with two baselines (TOOT and PINT) is used to flag strongly interactive PCIs, which in some cases could lead to a more detailed supplementary analysis. This recommendation can be implemented in the current institutional setting.

ENTSOs or Regional Groups should apply the CBA method rather than individual project promoters: promoters might lack the necessary resources and up-to-date information about the status of other PCIs to deal with the coordination among projects fully. The ENTSOs could play that role as it is an extension of what they already do in the context of the Ten-Year Network Development Plans (TYNDP), or the competencies of the Regional Groups could be expanded to allow a more active role in making a coherent selection of projects of common interest in their respective regions. This recommendation would require an improved institutional setting. Gorenstein Dedecca et al. (2017a) goes one step further with stating that Northern Seas offshore grid planning should be regional to avoid locking-out beneficial expansions.

Secondly, in the ENTSO-E methodology disaggregated reporting of costs is not a mandatory provision, likewise the geographically disaggregated reporting of the benefits, Thus it can be argued that the ENTSO-E methodology does not promote transparency enough for these aspects. Disaggregated cost reporting is of particular importance in the context of offshore grid infrastructure as the technology used for such projects is relatively immature making



it harder to estimate the exact costs. Discrepancies in cost estimations can be identified more easily when reporting of costs is disaggregated. Also, in offshore projects the welfare of typically more than just two countries is significantly impacted by a project, making cross-border cost allocation (CBCA) decisions harder to agree upon. The outcome of a CBA should be used as an input for these CBCA discussions, and therefore it is required that the benefits are reported in a geographically disaggregated manner.

When looking at the case studies, it seems that the costs are reported in a disaggregated manner without exception. In most case studies cost ranges instead of point estimates were used, which could be considered as a recommended practice. However, the cost categories applied in each case study differ significantly, making benchmarking very complex. In most case studies, also the benefits are reported in a geographically disaggregated manner. This shows that the opposition against making disaggregated benefit reporting obligatory can be expected to be limited.

Recommendation 2: to gain trust and public acceptance

Harmonised and disaggregated cost and benefit reporting: ENTSO-E is doing this already for benefits in another context than PCIs. ACER could impose it for benefits, as well as for costs in the context of PCIs for electricity (and for gas). Geographically disaggregated benefits would feed-in in the CBCA discussions, which are expected to be more complicated in the context of a meshed offshore grid. The assessed case studies show that even without a mandatory provision for doing so, such best practice is sometimes adopted. This recommendation can be implemented in the current institutional setting.

Open source CBA model (instead of common CBA method): When going one step further, not only more transparency in the input and output of the model could be demanded, but also in the modelling itself. National Grid, for instance, made its open source electricity scenario simulator available for other stakeholders to play with. The open source model could be made a responsibility of the ENTSOs as it is an extension of what they do in the TYNDPs. The model could also be made available under the patronage of the Regional Groups.

The third concern about the ENTSO-E CBA methodology is related to the final assessment of the project. The prerequisite for evaluating and comparing the net benefit of projects is that the results of the analysis are all on the same footing; in this case, the net benefit expressed in monetary terms. A multi-criteria CBA is proposed by ENTSO-E instead of a 'pure' CBA of which all benefits can be monetized and aggregated.⁴³ In the case of a multi-criteria CBA, monetization will happen implicitly when projects need to be selected and thus rendering it opaque. Alternately, project promoters will come up with their own numbers, creating discrepancies between projects of different promoters. Again, this concern is of vital importance in the offshore context as next to an increase of social-economic welfare, due to a more efficient dispatch in coupled markets, various externalities, such as the integration of renewables and an increase of security of supply, are expected to be significant.

⁴³ The fact that all benefits can be aggregated does not obviate the best practice of also reporting these per benefit indicator and in a geographically disaggregated manner for informational purposes.

When looking at the case studies, it can be seen that all final assessments differ, rendering comparison among the projects difficult. In the EWIC case, full monetization is applied using its own methodology. Benefits are partially monetized in the COBRACase, but this is not a critical issue in this case study as the most significant benefits, auction revenues from congestion on the cable (included in the socio-economic welfare) are monetised. In the ISLES case study, both quantitative as qualitative cost and benefit indicators are reported.

Recommendation 3: to reduce the politics in the valuation of (offshore) PCIs (or to move the politics from the economic assessment to the eligibility criteria at the start of the selection process)

Full monetization: ACER could simply require full monetization. If the ENTSO experts do not feel comfortable choosing a value for controversial factors such as VOLL or CoDU, ACER or the EC could appoint other experts to propose a value. This has already been done for the discount factors. It should also be noted that the ENTSO-E common CBA method for balancing market design already adopted the spirit of full monetization. Finally, note that Regions might still want to express their energy policy priorities, such as security of supply or integration of renewable energy. Today they can do that by attributing a different weight to different indicators from the MCAs. If we go towards a full monetization, that would not be possible anymore. Instead, Regional Groups could be asked to express their policy priorities via the PCI eligibility criteria. This would also be more transparent than working with weighing factors that are not known to the public.

In conclusion, in order to improve the effectiveness of the CBA in the selection process for energy infrastructure projects with a pan-European impact, it is recommended that the three identified concerns are addressed. Overarching these three issues is the demarcation of where ENTSO-E's responsibility regarding the CBA methodology begins, and where it ends. In ENTSO-E's opinion, it ends precisely where objectivity is no longer possible – hence, it's CBA methodology seeks a consistent & uniform way to report project effects. FSR and ACER, (2017) do agree with this statement but have different views on what can and what cannot be objectively determined.

The three (general) issues identified in this report are even more pronounced for offshore electricity transmission projects for several enumerated reasons. Within the current institutional setting, significant improvement can already be made, but also in the longer term the institutional setting could be improved. Coordination among projects is identified as being the hardest concern to address in the offshore context. Much uncertainty for individual project developers remains without a clear vision of what a future offshore meshed network in the North Seas will look like and could hamper future investment. A more radical idea would be to assign the task of planning this future network to a qualified entity, already existent or to be created. This planner could also become the operator of the meshed offshore network, similar to the US ISO model. Cables making part of this plan could then be tendered out as individual projects to third parties, including existing onshore TSOs. In such a setting, more robust planning and compatibility among individual projects are ensured, and competition, to allow investments to be cost efficient, is introduced. However, this idea would require a complete change in the current governance model and can be worked out in future deliverables as its implications are outside the scope of this document.



3 OFFSHORE GRID PLANNING II: COORDINATING ONSHORE-OFFSHORE GRID PLANNING

3.1 INTRODUCTION⁴⁴

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 12.

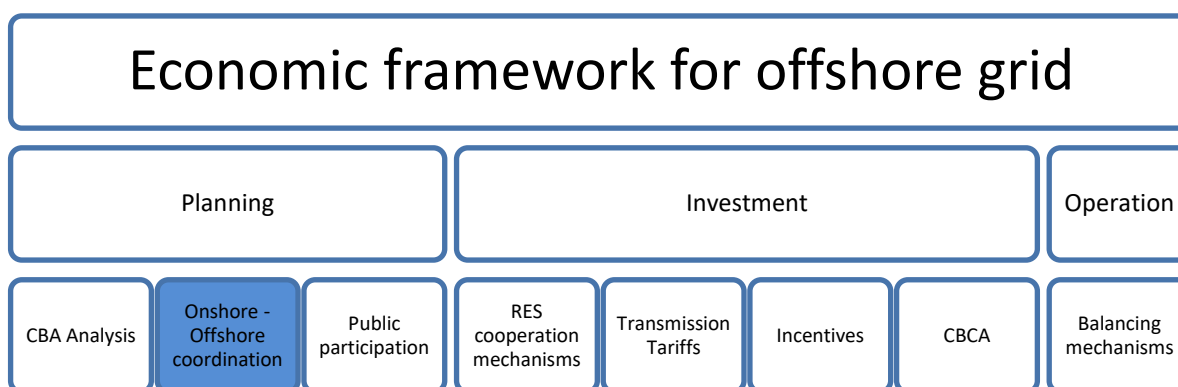


Figure 12: : Illustration indicating the position of this chapter in the overall report structure.

The key to a successful implementation of an integrated approach to offshore grid development in the North Sea is the coordination among various stakeholders. In this chapter, we study the interaction between onshore grid development, traditionally performed by TSOs, and the development of offshore grid infrastructure. We follow a case study approach to investigate how onshore-offshore coordination of grid development is carried out in a national context. We identify the key onshore-offshore coordination issues that may impact the development of the required offshore transmission infrastructure and the necessary onshore reinforcement.

Within each case study, we first present a brief overview of the offshore wind generation development in the country under consideration. The overview is followed by a description of the historical development of the relevant regulatory instruments that have been utilised by the member state for offshore wind development. The past and current policy choices are classified into the three dimensions for each case study. These three dimensions to analyse offshore-onshore coordination are based on the review of the literature on the topic of offshore infrastructure planning to accommodate offshore generation (European Commission, 2016a; Fitch-Roy, 2015; González and Lacal-Aránategui, 2016; Hooper, 2015; Meeus et al., 2012). The three selected dimensions are **locational requirements for renewable energy support**, **onshore grid access responsibility** and **grid connection charges**. For each dimension, three possible regulatory practices are identified. After the assessment of the individual countries, a comparative analysis is conducted with the aim of providing an insight into the general trend in the policies that govern the development of new offshore wind farms within the three dimensions.

⁴⁴ Also see Meeus and Schittekatte, (2018b) for discussion on this topic.

The chapter is organised as follows. In the next section, the applied methodology is elaborated. Afterwards, the four different country cases are presented and analysed. Following the assessment of the individual countries, a comparative analysis is conducted. Finally, a conclusion is presented.

3.2 METHODOLOGY

3.2.1 CASE STUDIES

We analyse onshore-offshore coordination in four countries, each representing a different approach. The selected states are Germany, Denmark, the UK, and Sweden. In recent years, Germany has added a significant quantity of offshore wind capacity, and more is planned (Aitken et al., 2014) which makes it an important case study for this analysis (WindEurope, 2017). Furthermore, the delays in offshore and onshore grid development have (Kostka and Anzinger, 2015) opened the door to the introduction of new approaches to manage offshore-onshore coordination in Germany (Hooper, 2015). This factor reinforces the relevance of analysing the German case in our study. Denmark was one of the pioneers of offshore wind development. Its regulatory framework for on-and offshore generation is often presented as a leading example (see: (González and Lacal-Aránegui, 2016)). The UK was selected as it is the state with the largest capacity of offshore wind connected to its onshore grid in Europe and has a unique regulatory framework in place for the governance of offshore transmission assets. Finally, the Swedish case is analysed as offshore wind development is very limited in the EU member state, even though there is a potential for offshore wind power development (Jacobsson et al., 2013). Moreover, the Swedish Energy Agency is currently considering changes to its regulation for encouraging offshore wind (Swedish Energy Agency, 2015; Weston, 2016). In the remainder of this section, we describe the three dimensions of onshore-offshore coordination in more detail as well as the two overarching perspectives used to cluster the regulatory frameworks of different countries.

3.2.2 THE THREE REGULATORY DIMENSIONS

3.2.2.1 LOCATIONAL REQUIREMENTS FOR RENEWABLE ENERGY SUPPORT

In the context of planning offshore wind development, locational requirements for RES support can be described by the question “where can a wind developer site an offshore wind farm?”. While deciding upon a site for developing an offshore wind farm, one needs to take various constraints into consideration. These may consist of social, environmental, economic and technological limitations. Therefore, during planning, effective coordination of various agencies is required. Moreover, the location of offshore wind farms has a direct consequence on the development of the offshore grid and especially its access to the onshore network and makes the siting of the wind farm a critical issue from the perspective of network development planning.

The **three regulatory strategies** that are described below allow a varying degree of freedom to the developer in selecting the location of a new offshore wind farm and concurrently avail the renewable energy support.



- a. **Open-door:** In this approach, the offshore wind developer selects the site for the wind project and proposes it for consideration to the appropriate national authorities. This approach allows the developer maximum flexibility in deciding the location of the wind farm. However, the final approval remains subject to the approval of various stakeholder agencies.
- b. **Zone-approach:** In this approach, the authorities identify a zone for offshore wind development using marine spatial planning techniques. The development rights for the construction of a single wind farm within the zone are then offered to prospective developers. The developers are allowed flexibility over the final location of the wind farm within the zone.
- c. **Single-site:** In this approach, the relevant authorities identify sites for offshore wind development using marine spatial planning techniques. This site is then offered to prospective developers for building a wind farm. Unlike the zoned approach, in a single-site approach the development is location specific.

3.2.2.2 ONSHORE GRID ACCESS RESPONSIBILITY

Providing an offshore wind farm with the access to offer the power that it generates to the load centres as efficiently and as effectively as possible is an important dimension for the success of any such project. This dimension has a major impact on the timeline of a project. A high risk for delays in onshore connection leads to investor uncertainty, reducing the incentive for developers to invest in new projects and impacting the cost of financing. Additionally, after the offshore grid connection is in place, outages due to the poor quality of the offshore connection and possible congestion at the onshore connection point can affect the business case of the offshore wind developer.

Onshore grid access responsibility consists of the four key pillars of grid development: planning, building, owning and operating of the offshore wind connection. Please note that it is not always the same actor who plans, builds, owns and operators the offshore connection. A mixed approach is possible. **Three strategies** for onshore grid access responsibility are identified: the TSO-led, the developer-led and third-party-led model.

- a. **TSO-led model:** In this approach, the transmission system operator is mandated by the concerned authority to be responsible for connecting the offshore wind farm to the onshore grid. Therefore, the entire process is planned and executed solely by the incumbent transmission system operator. Generally, TSOs are responsible for providing the connection within a specified time frame. The inability to do so would lead to financial penalties for the TSO.
- b. **Developer-led model:** In this approach, the offshore wind farm developer is solely responsible for connecting the wind farm to the onshore grid. This approach is especially advantageous in scenarios where the location of the wind farm is uncertain (such as in an “open-door” scenario) where it becomes apparent that the developer is better placed to plan the offshore connection.
- c. **Third party-led model:** In this approach, the grid access responsibility lies neither with the incumbent TSO nor with the wind farm developer but with a third party. When the decision to develop an offshore wind farm is made, a third party grid developer is mandated to connect the wind farm to the onshore grid in a specified time frame.

3.2.2.3 GRID CONNECTION COSTS

What part of the grid infrastructure does the developer pay? The answer to this question may not only have an impact on the decision of the offshore wind developer to invest in a project but also on the incentive of this offshore wind developer to connect the wind farms to the shore at a connection point where the incremental cost for the network is minimal. In the broader system perspective, it is critical to have the right coordination between the actor responsible for grid access and the one that is responsible for paying the grid connection costs. The grid connection costs can be attributed to the wind generation developer based on **three strategies** that are illustrated in Figure 13: Charging of grid connection costs to offshore wind developers – super-shallow (developer pays:1), shallow (developer pays:1+2) and deep (developer pays:1+2+3). Source figure: <https://corporate.vattenfall.com/>, namely: super shallow, shallow and deep. The approaches are based on the extent to which the developer is exposed to the costs of building the offshore grid connection and the necessary reinforcements that may be required to the onshore network.

- a. **Super shallow:** In this approach, the wind farm developer is responsible only for the cost incurred for developing the internal network within its wind farm. The costs of the offshore grid connection and for any necessary onshore reinforcements that may be needed to accommodate the offshore connection are socialised.
- b. **Shallow:** In this approach, the generator is responsible for the cost incurred in developing the internal network within the wind farm as well as the cost of connection up to the onshore connection point. Any costs that may be incurred for onshore reinforcements are socialised.
- c. **Deep:** In this approach, the wind farm developer is responsible for the entire grid connection cost. Therefore, the developer pays for the internal network within the wind farm, the connection from the wind farm to the shore and the costs that may be incurred for reinforcing the onshore network to accommodate this resource.

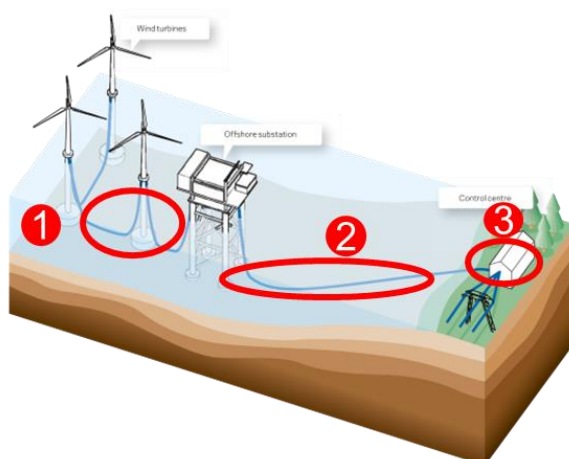


Figure 13: Charging of grid connection costs to offshore wind developers – super-shallow (developer pays:1), shallow (developer pays:1+2) and deep (developer pays:1+2+3). Source figure: <https://corporate.vattenfall.com/>

3.3 CASE STUDIES

3.3.1 GERMANY

Germany has been a world leader in the transition to a decarbonized electrical system. Development of offshore wind farms is a fundamental component of the German renewable development strategy. As of 2015, Germany has the second largest installed offshore capacity of roughly 3.3 GW.

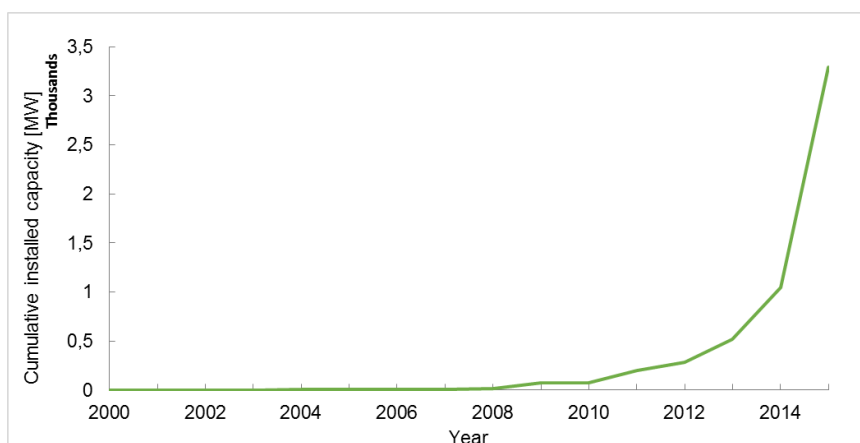


Figure 14: Offshore wind installed capacity trends in Germany.

The offshore wind industry in Germany has made rapid strides since the commissioning of the first offshore wind farm in the year 2009, as can be seen from Figure 14. In 2015, 2.3 GW of new capacity was brought online, accounting for 75.4% of all new offshore wind capacity that was brought online in 2015 in Europe. However, it should be noted that much of this capacity addition in Germany was delayed due to the inability of the TSO in connecting these wind farms to the onshore grid on time (see box). Thus the capacity became available concurrently when this hurdle was resolved (EWEA, 2016) In 2016 813 MW of offshore wind capacity was installed in Germany (WindEurope, 2017).

Grid access delays

The delay in grid connections has been a serious issue in Germany in recent years and demonstrates the relevance of coordination between onshore and offshore planning.

In the initial period for offshore wind development, under the 2006 Infrastructure Planning Acceleration Act (IPAA), the German TSOs were requested to connect the wind farms under construction before 2015. By 2012, the installed capacity had reached only 280 MW. The slow development in contrast to the concurrent onshore wind boom was due to two primary factors (Kostka and Anzinger, 2015).

Firstly, on the one hand, the TSOs were only willing to commit to grid connection when the financing for the wind farm was secured, while on the other hand, the financial institutions viewed grid connection certainty as a prerequisite for issuing loans to wind farm developers thus causing a circular problem.

The second reason for delays in grid connection is financing constraints and the supply chain bottleneck. When TenneT made the acquisition of the Northern German TSO from E.ON, there were already 23 offshore grid connections that had been approved in Germany. In 2011, TenneT had revenue of € 1.5 billion and a net profit of €200 million, while the transmission investment required for the Netherlands and Germany in the coming ten years was estimated to be €20 billion (Kostka and Anzinger, 2015). Thus, under financial stress and personnel shortage, TenneT suspended the construction of these grid connections until the regulatory and financial issues were resolved.

Additionally, according to literature, the supply of cables and substation was unable to follow demand when the demand initially increased. This along with the low maturity offshore substation technology caused delivery uncertainties throughout the supply chain. However, in the next two years, the logistical and financial constraints eased leading to a significant expansion of the offshore network.

The regulatory framework for German offshore wind generation is currently under transition. Both the new system that is being enforced and the previous regulatory framework are described.

3.3.1.1 FROM OPEN-DOOR TOWARDS A SITE SPECIFIC APPROACH

Since 1997 until the 31st December 2016, German offshore wind development has been governed by the Energy Industry Act (EnWG) and the Renewable Energy Act (EEG). A Marine Spatial Plan, developed by the federal marine and Hydrographic Agency (BSH) and the federal network agency (BNetzA) that demarcates priority areas for offshore wind farm development was enforced in 2009. The plan aims to ensure coordinated and consistent spatial planning of grid infrastructure, especially for offshore wind farms in the German EEZ in the North and Baltic seas. From 2013 onwards, additionally and closely linked to the Marine Spatial Plan, an annual Spatial Offshore Grid Plan⁴⁵, to be published by BSH, and an Offshore Grid Development Plan (O-NEP), to be issued by the TSO's, was introduced. However, wind farm developers could still present proposals for new projects in other regions which would then be evaluated depending on their ability to adhere to all permissibility criteria. It can be said that Germany has applied an **open-door approach** regarding the locational requirement of offshore wind farms.

The Windenergie-auf-see-Gesetz (WindSeeG) that came into force on January 1st, 2017 will now govern offshore wind projects. Projects that already receive an unconditional grid access confirmation, or an allocation of connection capacity before 1 January 2017 and that will be commissioned before 2020 are exempted from the auction. These projects will be subject to the EEG 2017, which contains a transitional provision towards the auction system. This is in the interest of coherence and predictability that is needed in the German offshore wind sector. The WindSeeG has made a significant systemic change to the regulation that governs the developing new

⁴⁵ For more information please see: http://www.bsh.de/en/Marine_uses/BFO/index.jsp



offshore wind farms by introducing centralised auctions. In this system, an auction of preselected sites will be conducted by the appropriate government agency. In this centralised model, the pre-selection and preliminary site investigations are performed by state authorities to determine the suitability for the operation of potential offshore wind farms.

An Area Development Plan (Flächenentwicklungsplan) which will be established by the BSH and BNetzA will replace the Spatial Offshore Grid Plan and the O-NEP. The latest Spatial Offshore Grid plan and O-NEP is published in 2017, and these plans would be replaced by the area development plan from 2026 (Watson Farley & Williams, 2016). The new Area Development Plan will not only include the sites, capacity of offshore wind farms, and time sequence for auction process but also will determine the locations of converter platforms and substations as well as connection cable routes. Also, the commissioning of a wind farm and their respective grid connections is foreseen to be included in the Area Development Plan. In summary, regarding the locational requirement of offshore wind, the new regulation introduces a **single-site approach**.

3.3.1.2 GRID ACCESS RESPONSIBILITY

Since 2006, the German TSOs are required to plan, invest and operate the offshore transmission network in Germany. Therefore, the grid access responsibility in Germany is **TSO-led**. Germany has four TSOs of which two, Tennet and 50Hz, operate in adjacent sea territory. The way offshore grid connection is organised by the TSOs in Germany can be split up into two periods, with a regime switch around 2013.

In the first period, it could be said that a “reactive/following TSO model” was applied. Grid connection was legally guaranteed and therefore was not a part of the wind park developers’ responsibility. The government obligated the relevant TSOs to provide a guaranteed grid connection. Anziger and Kotska (2015) state that this regime: “Expecting guaranteed grid connection, wind park developers staked maritime claims and started construction.” On a more positive note, at the same time, the regulatory frame already allowed the TSO to make anticipatory costs (see box), making it possible to create hubs and profit from economies of scale (Meeus et al., 2012).

BorWin: wind park hub of Borkum Island

Originally the Borwin hub was planned to consist of 4 phases. High Voltage Direct Current (HVDC) Voltage Source Converter (VSC) systems, one for each phase, had to be used to connect the offshore wind farms to the transmission grid of the TSO in the area because of the relatively large distance to shore. These HVDC VSC systems consist of a DC cable with two converter stations, one to convert the AC output of the wind turbine into DC, and one to reconvert the DC output of the cable into the AC of the onshore grid.

The finalised Borwin1 and Borwin2 projects connect a total of three offshore wind farms located about 125-150 km from shore, and total 1200 MW (i.e. 400 MW in Phase 1 in started in 2009 and 800 MW in Phase 2 began in 2012). Its connection cost has been estimated at 1200 million Euros.⁴⁶ The projects were highly innovative

⁴⁶ <http://www.reuters.com/article/tennet-idUSLDE73S0QH20110429>

as BorWin1 was the first HVDC facility in Germany to use VSC⁴⁷ and BorWin2 the first system offering a connection to more than one offshore wind farm.⁴⁸

Currently, also BorWin3 is being constructed and expected to come online in 2019. The link will transmit approximately 900 MW of wind power. The awarding procedure for the originally planned Borwin4 900MW grid link has been halted, and project links reallocated. A Tennet spokeswoman said that the BorWin 4 link is not part of offshore grid development plan (O-NEP) for the next ten years.⁴⁹ An overview of the four original phases of the Borwin hub is shown in the table below.

Table 3: Overview of the Borwin hub, Adopted from Anzinger and Kostka (2015)

Project name	Status	# OWF planned to be connected	Capacity (MW)	line
BorWin1	Online in 2009/2010*	1	400	
BorWin2	Online in 2015	2	800	
BorWin3	expected 2019, in construction	1	900	
BorWin4	expected 2019, halted	1	900	

* The project has had many technical difficulties since that date

Joint planning means that economies of scale could be profited from. As transmission capacity has only little impact on the overall price, recent projects are tendered independently of announced OWF capacity.⁵⁰ In the case of Borwin2, the coordination of the connection of the two wind farms in an early stage meant that only two converter stations and one cable to shore needed to be used, instead of 4 stations and two cables. Furthermore, by building offshore projects near to one another, operators ensured that the environmental impact, the costs associated with preparing the cable corridor and the costs of possible reinforcements needed onshore could be reduced.

In response to the difficulties experienced with offshore grid connecting as described, the government undertook a reform program that substantially transformed the regulatory and policy framework, and this even before the introduction of the new regulatory framework WindSeeG in 2017. A milestone was the introduction of the Offshore Grid Development Plan (O-NEP), briefly mentioned in the previous section. From 2013 onwards, the German TSO's were required to deliver the O-NEP to the BNetzA (Hooper, 2015). It was the first document to unite the development of the transmission system on land, the spatial planning at sea and the technical framework conditions for sustainable planning, with detailed information on the status, schedule, deadlines and costs of the projects. This plan with a horizon of 10 years facilitated better the coordination (mainly in the form of hubs) of different offshore projects and allowed the TSOs to plan their budgets more carefully. The developer's right to request connection was replaced by an objective, transparent and non-discriminatory allocation procedure that

⁴⁷ Source : <http://tdworld.com/underground-tampd/north-sea-wind-power-comes-ashore>

⁴⁸ Source: <http://www.offshorewind.biz/2015/02/03/tennets-first-major-offshore-wind-grid-connection-operational/>

⁴⁹ Source : <http://www.windpoweroffshore.com/article/1376471/borwin-4-contracts-halted>

⁵⁰ Tennet, 2014, ' Cost Reduction Potential in the Offshore Grid', presentation by M. Glatfeld

allows for transmission assets to be shared across individual wind farms by amendments to the EnWG in 2012/2013.

3.3.1.3 GRID CONNECTION COST

In Germany, a **super shallow grid connection cost** scheme is in place. The offshore generation developer does not pay for the grid connection; the cost is socialised by the TSO charging levies to the consumers (European Commission, 2016a; Fitch-Roy, 2015; Hooper, 2015).

In Germany, RES has priority of connection which refers to the order of connecting generators which have applied for grid connection. However, it is unlikely that offshore RES plants will be in competition with non-renewables for grid connection at the same point, because the connection to the onshore grid will be at dedicated points, explicitly built for an offshore generation. Therefore, competition for connection capacity will be between offshore RES projects themselves. At present, there is a lack of appropriate rules to decide how connection capacity is allocated between RES projects (e.g., pro-rata basis; curtailment rules, first come first served). In Germany, a round-based tender process has been introduced to deal with situations where the demand for connection surpasses the free capacity on a grid connection line (European Commission, 2016a).

3.3.1.4 FUTURE OUTLOOK

Increasing the share of power generated by renewable energy sources remains the main component of Germany’s proposed energy transition. Last year, the government extended the country’s support for offshore wind until the end of this decade, however, in 2014 offshore capacity targets were reduced to 6.5GW by 2020, and 15GW by 2030 (down from the previously planned 15GW and 25GW respectively).⁵¹

The first auction under the WindSeeG is planned for March 2017. A five-year lead time is envisaged for the offshore wind farm projects, which means that the TSO will have five years to install the necessary DC network in the North Sea. First, a transitional regime will be in place for offshore wind farms commissioned between 2021 and 2025 before the new "central" auctioning concept is fully implemented.

From 2021 onwards, annual auctions will be organised following the pay-as-bid approach for capacities between 700-900 MW located at sites for which the preselection and preliminary investigation will be performed by governmental authorities. The successful bidders will obtain the development rights of the wind farms for 20 years. For these offshore wind farms, expected to be commissioned from the beginning of 2026, the WindSeeG provides for a complete change to the so-called “central model.”

3.3.1.5 SUMMARY

Table 4: Summary of the German approach with respect to the three dimensions.

Dimension	Strategy	Approach	
		Old	New

⁵¹ “In depth: German offshore upbeat” article by B. Radowitz (2014), link: <http://www.rechargenews.com/magazine/865244/in-depth-german-offshore-upbeat>

Locational Requirement	Open-door	✓	
	Zoned		
	Single-site		✓
Grid access responsibility	TSO	✓	✓
	Developer		
	Third party		
Grid connection costs	Super shallow	✓	✓
	Shallow		
	Deep		

3.3.2 DENMARK⁵²

Denmark has the third largest capacity of offshore wind farms in the world (EWEA, 2016). In fact, the first ever demonstration project on the use of offshore wind turbines for generation of electricity was built off the coast of Denmark in 1991 at the Vindeby offshore wind farm. This project gave impetus to the construction of more such demonstration projects, finally leading to the world's first two commercial offshore wind farms: Horns Rev I (160MW) commissioned in 2002 and Nysted (165MW) commissioned in 2003 (Danish Energy Authority, 2015). As of 2014, Denmark has an offshore wind generation capacity of roughly 1.27 GW (EWEA, 2016). Please see (WindEurope, 2017) for more statistics on offshore wind in Denmark.

In the 70s, Nuclear power was expected to play a central role in the future electricity supply mix. The first Danish energy plan that was presented in the year 1976 indicated a strong commitment of the Danish government towards induction of Nuclear Power. However, this caused a decade-long debate among various stakeholders on possible alternatives (Meyer, 2007).

Wind energy emerged as the technological option with the most potential for further development from a Danish perspective. Eventually, in 1985, the Danish parliament decided that Nuclear power would not be part of the future Danish electricity supply mix (Meyer, 2007). The Danish energy plans presented in the 1990s put emphasis on sustainability and reduction in greenhouse gas emissions. Since then, Danish policymakers have set and achieved ambitious RES targets.

Consequently, rapid growth in wind power generation, onshore and offshore, has been observed (aided by effective renewable support schemes). The share of wind power in domestic electricity supply increased from 1.9% in 1990 to 19.1% in 2008 and 39% in 2014 (Danish Energy Authority, 2015). The current Danish climate policy plan has set a target of making electricity and heating 100% renewable by 2035. Of all RES sources, wind energy is expected to play the crucial role in this transition (EFKM, 2013).

Initially, wind power development was focused on building onshore wind farms that were subsequently repowered to increase their capacity. However, now the focus has shifted to offshore wind farms. There are two main drivers for this change: the first is the scarcity of sites for building new onshore wind farms in a country with a limited land

⁵² Based significantly on the description in (Danish Energy Authority, 2015, 2005)

area and a high population density and the second is a high potential for offshore wind due to the long coastline. The wind potential off the Danish coast is estimated to be around 20TWh/year (Meyer and Koefoed, 2003). To put this number in perspective, the electricity consumption of the country was 33.6 TWh in 2015.⁵³ Figure 15 presents the growth in the offshore wind capacity since the beginning of the new millennium.

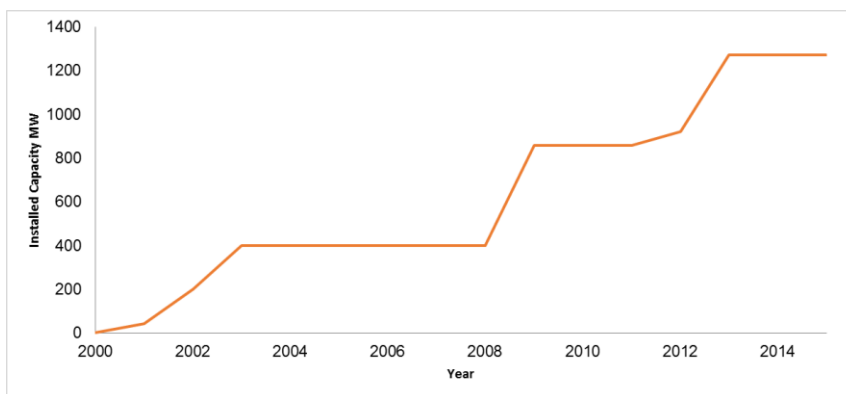


Figure 15: Cumulative installed capacity of offshore wind in Denmark

Denmark has two regulatory approaches towards the development of new offshore wind farms. The first is government tendering of pre-identified sites and the second is an open-door policy wherein a developer may propose a site for developing a new offshore wind farm. Apart from these two development pathways, a different process is used for the development of near-shore wind farms. In the following sections, we discuss the various regulatory approaches of Denmark for the planning and development of offshore wind farms. It should be noted that although we discuss all available regulatory approaches, namely offshore tendering, ‘open doors’ and nearshore tendering, the majority of the investments that have occurred in Denmark have been through offshore tendering⁵⁴ only. Therefore, this can be considered as the most relevant approach from the context of this chapter.

3.3.2.1 OFFSHORE TENDERING

The tendering process for a new offshore wind project is conducted by the Danish Energy Agency (DEA). The DEA specifies the geographical location and the size of the project that is to be tendered (Fitch-Roy, 2015; Meyer, 2007; Munksgaard and Morthorst, 2008). Therefore, this approach could be considered as **single-site** from the perspective of the “locational requirement” dimension.

Spatial planning techniques have utilised the identification of sites for the development of new offshore wind farms. A spatial planning committee led by the DEA and consisting of government agencies responsible for aspects such as environment, marine navigation, transmission planning, etc. along with wind energy experts performs this task of identifying new sites. This committee was constituted 1995. The first report identifying sites for offshore wind development was published in 1997. The report was followed by the second report titled “Future Offshore Wind Turbine Locations – 2025” that was released in 2007 and updated in 2011 (Danish Energy Authority, 2007).

⁵³ <http://www.energinet.dk/EN/KLIMA-OG-MILJOE/Miljoerapportering/Sider/Forbrug-i-Danmark.aspx>

⁵⁴ Historically 64% capacity has been installed utilizing the tendering approach, while roughly 30% are early demonstration projects built under obligation by the utilities. Only 5% have been built through the open-door approach (estimated from: Danish Energy Agency, (2015)).

Applications are invited from interested parties for the development of the site under consideration. The prospective concessionaires are expected to bid the fixed feed-in tariff for which they are willing to produce electricity for certain full load hours. The most competitive bid is awarded the concession to develop the site. Figure 16 presents the depiction of the various steps in the tendering process.

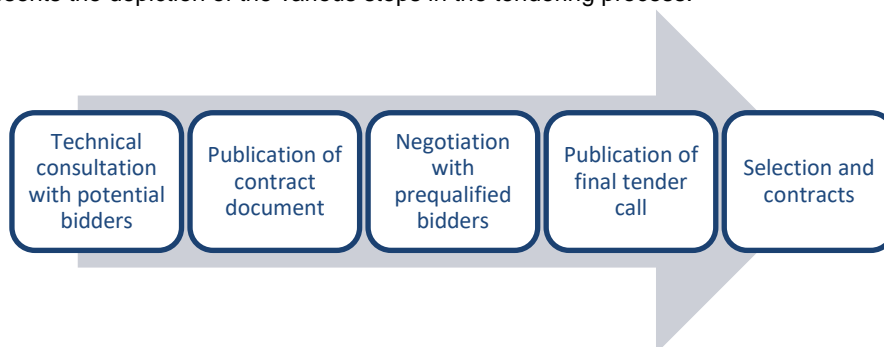


Figure 16: Depiction of the tendering process.

For a government tendered offshore wind farm project, the TSO is responsible for owning, constructing and maintaining all the infrastructure needed for connecting the offshore wind farm to the grid. This is the responsibility of the Danish TSO Energinet.dk. Large wind farms have their internal grid that is owned and operated by the producer. The internal grid is connected to a transformer platform. The transformer platform is then connected by a cable (100KV) to the onshore grid. This offshore infrastructure is owned and operated by the TSO.

Furthermore, these large offshore wind farms are connected to the onshore transmission grid at areas with low population. Therefore, until now, there has been no need for additional grid reinforcement for connecting offshore wind to the onshore network. However, with greater penetration of offshore wind in the future, significant grid reinforcements may be required. The connection of offshore wind farms is directed by Technical Guidelines TG 3.2.5 of the Danish TSO Energinet.dk (Danish Energy Authority, 2005).

Therefore the “grid access responsibility” lies with the **TSO** and the connection costs for the developer of such projects can be considered as **super shallow**. It should be noted that Denmark follows a non-discriminatory connection regime for connecting renewables to the grid.

3.3.2.2 OPEN-DOOR APPROACH

In an open-door approach, a project developer proposes the development of an offshore wind farm by submitting a voluntary application for a license for a preliminary investigation of a particular area where the wind farm is proposed to be built. The location and size of the project are proposed by the project developer. However, these sites cannot be any of the sites that have been identified in the Future Offshore Wind Power Sites – 2025, published in 2007 and extended in 2011. As stated in the name, the locational requirement is **open-door**. In this approach, the project developer is responsible for paying the cost of transmission infrastructure as the size and location of the wind farm is unknown. Therefore, the grid access responsibility is with the **developer** and the grid connection costs can be considered **shallow**.

The application submitted to the DEA must provide a detailed description of the project that includes the scope of the site investigations, dimensions of the wind farm regarding capacity and number of wind turbines and geographical size covered. The DEA reviews the application and coordinates with other relevant agencies to ensure that there are no objections to the development of the project. If the outcome is positive, a license for a preliminary investigation is granted to the project developer.

Depending upon the final findings of the preliminary investigations, the project developer may be granted a license to develop the wind farm.

3.3.2.3 NEAR-SHORE WIND FARMS

In 2012, the spatial planning committee published a report listing 15 sites for near shore wind farm development. However, these wind farms have to be situated at least 4 km from the coast. The Danish parliament has decided to allow bids for development of 350MW of near-shore wind farms at six sites each with up to 200MW capacity. The preliminary survey of these locations would be conducted by the TSO, and this information would be provided to the bidders. However, the winning concessionaire will have to pay back the cost of this survey to the TSO. The approach can be considered as a **zoned** approach as competition is between sites that have been identified by DEA.

Since the start of the wind revolution in Denmark, social acceptability has been considered a critical aspect of its development. The social acceptability aspect includes responsible and holistic site selection procedures. The Energy Policy Agreement of 2008 added more initiatives for the further promotion of local acceptance. One unique aspect of the Danish wind industry is that most onshore Danish turbines are owned by neighbourhood cooperatives. The cooperative ownership of wind turbines can be considered as one of the key driving forces for greater social acceptability of wind energy in Denmark (Danish Energy Authority, 2015). Therefore, these six sites have been selected keeping in mind the favourable public sentiment in these regions towards wind development. Moreover, the developers are obligated to offer 20% share to residents and enterprise (however it is not necessary to achieve this objective). If the public ownership is 30% or more, a higher feed-in tariff will also be offered to the project.

As the location and size of the wind farm would be unknown until the conclusion of the tendering process, it is reasoned that a developer-led approach would minimise the risk of any coordination issues that may arise in the planning of the connection due to the constraint mentioned above. Thus, the planning and cost of connection to the nearest point on the coast will be borne by the developer. Therefore, the grid access responsible party is the **developer** and the grid connection costs for such projects can be considered as **shallow**.

3.3.2.4 FUTURE OUTLOOK

In the tendering approach, the tendering price is very project specific and would differ depending upon the various conditions at the site being tendered along with the technological and market conditions at the time of tendering. Secondly, a recent report by the DEA states explicitly that “A government tender is carried out to realise a political



decision to establish a new offshore wind farm at the lowest possible cost.” (Danish Energy Authority, 2015). This gives a good indication of the centrality of political will in the decision making on the development of new offshore wind farms in Denmark. Also, it should be noted that the tendering approach has been consistently used by DEA since the beginning of large-scale offshore wind development in Denmark. As discussed in the earlier section, the development of near-shore wind farms is also expected shortly.

3.3.2.5 SUMMARY

Table 5: Summary of the Danish approach with respect to the three dimensions

Dimension	Strategy	Approach		
		Tender	Open-door	Nearshore
Locational Requirement	Open-door		✓	
	Zoned			✓
	Single-site	✓		
Grid access responsibility	TSO	✓		
	Developer		✓	✓
	Third party			
Grid connection costs	Super shallow	✓		
	Shallow		✓	✓
	Deep			

3.3.3 UNITED KINGDOM

The United Kingdom has the highest installed capacity of offshore wind farms in the EU. Since 2000 when the first 4MW prototype was commissioned, a rapid increase in offshore wind capacity has been observed, especially since 2010 (see Figure 17). As of 2015, the UK has a total offshore wind installed capacity of roughly 5GW.

After a prototype 4MW test site in 2000, the UK commenced offshore wind farm development with ‘Round 1’ of site leases. Five pilot sites were developed from 2003 to 2008 with a total capacity of 390MW. These had typically no more than 30 turbines and were close to shore. Sites were selected by the developers. The UK’s ‘Round 2’ of site leases consisted of a further 8GW of sites, mostly off the East Coast. The distribution was within 12 nautical miles (nm) of shore at depths of up to 20m with a few under construction at depths of up to 35m (e.g. Thornton Bank and Greater Gabbard). These were larger in scale and further offshore.

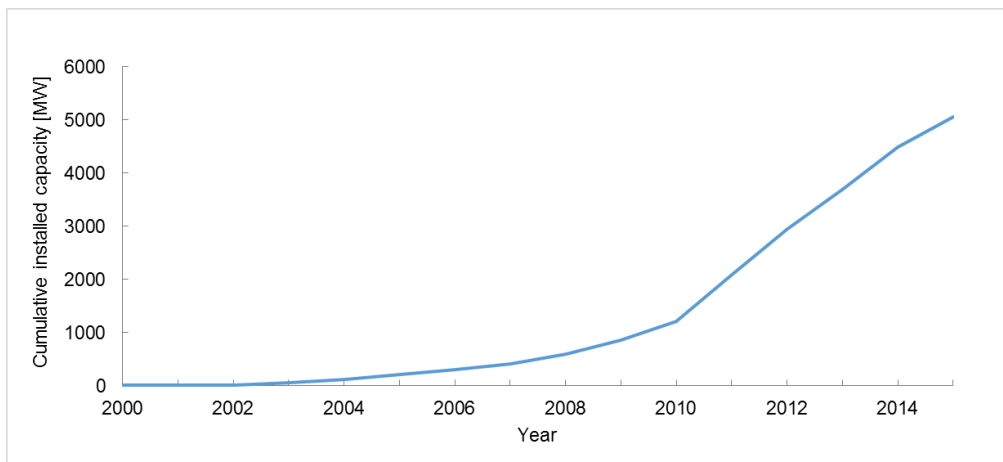


Figure 17: Offshore wind development trend in the UK.

Round 3 identified up to 33 GW of offshore wind development in the UK Renewable Energy Zone across 9 zones. In contrast to the first two rounds, zones in the third round were competitively tendered. The Crown Estate identified the zones. However, the responsibility was on the developers to find specific project sites within their allocated zones, using engineering, economic and environmental analysis to identify the best options. Round 3 sites were further offshore and larger in scale. At the same time as Round 3, extensions were granted to Round 1 and Round 2 sites. It has been noted that the scale of the Round 3 leasing round was overly ambitious, setting unrealistic expectations for the sector.

The UK (DECC) undertook a strategic assessment when assessing Round 3 sites, which informed Round 3, ultimately assisting in identifying nine development zones with potential for ~26 GW of installed capacity. Combined with other development rounds, this brought potential installed capacity to over 40 GW in UK waters, acting as an important catalyst and enabler for offshore wind development in the UK.

The fourth tendering round is anticipated to take 18 months from start to finish, i.e. the Enhanced Pre-Qualification Document was made available in April 2016 and the final selection of the preferred bidder is anticipated in March 2017.

3.3.3.1 OFFSHORE TENDERING PROCESS

The Crown Estate and Department for Business, Energy and Industrial Strategy (formerly DECC) are responsible for identifying zones for offshore wind development, and developers are responsible for identifying which areas within each zone are suitable for construction, and which specific sites in those areas are best suited for project development.

The Crown Estate is the principal owner of the UK's seabed and holds management rights to renewable energy on the Continental Shelf. Applications, with criteria covering technology, H&S, finance and overall business planning, are made to the Crown Estate. If an application is successful an 'agreement for lease' is awarded, which gives the developer an option over the site – usually subject to several conditions. Once consent and financial

closure have been achieved, the full lease is awarded by the Crown Estate. Currently, commercial-scale offshore wind project sites in the UK are determined using the Strategic Environmental Assessments (SEA) guidance as a systematic decision support process, although the last exercise took place in 2001. The exercise included assessment of suitable National Grid connections and was undertaken by DECC, Marine Scotland and the Crown Estate.

The Crown Estate's centralised government authority over the seabed is highly useful for developers since it streamlines the approvals process considerably. The Crown Estate outlines the zones in which offshore turbines can be built. Therefore, developers do not have to engage with any other agencies (e.g. the Ministry of Defence, the Department of Environment, Food and Rural Affairs, Department of Transport's Maritime and Coastguard Agency, etc.). In 2008 and 2009, using the information which was available, the Crown Estate identified large areas of the seabed around the UK which are the most suitable for offshore wind development. In 2009 The Crown Estate ran a competitive tender process and awarded these Round 3 zones to different offshore wind developers. In parallel, The Crown Estate undertook a Habitats Regulations Assessment (also known as Appropriate Assessment) about the Round 3 tender program. This was required under the UK Habitats Regulations, which are derived from the European Habitats Directive and Birds Directive.

The second stage in the process of deciding where to locate offshore wind farms within the Round 3 zones – the zone and project planning stage – is the responsibility of the offshore wind developer who has the rights for the zone. Offshore wind developers can look for wind farm projects within the boundary of their Round 3 zone. They are currently undertaking survey work and studies to help them understand the most appropriate locations for offshore wind farm projects within the zone. They will take into consideration engineering, economics, and environmental factors when deciding on the locations of wind farms to help them determine operational and financial feasibility.

Site selection is especially reliant on high-quality wind speed data since it is the biggest determinant of the long-term profitability of a project. A significant amount of innovation has been put into lowering the cost of gathering site-specific data while improving accuracy.

The UK has carried out three rounds of offshore wind tendering (denoted as 'Round 1, Round 2, and Round 3). The process of selecting sites has not drastically changed over the course of these rounds. However, incremental improvements have taken place. The first two could be classified as 'open-door' with the third following a more zonal and coordinated approach.

3.3.3.2 REASONS FOR CHANGING FROM OPEN-DOOR TO ZONAL APPROACH

As a pioneer in offshore wind and with a vast coastline there were initially many uncertainties, for both developers and government in the UK. In the early days, offshore wind was an unproven technology and the characteristics of the seabed largely unknown. The first and second offshore site identification rounds were '**open-door**' (and therefore developer driven) and faced many uncertainties, which ultimately led to many untenable sites being



secured with some of these falling through at significant cost to the developer and expended effort on behalf of government bodies.

Feedback loops and a better comprehension of site characteristics led to the increasing use of constraints in the buildup to the Round 3 tender of sites, which resulted in nine zones identified for offshore wind. Within these zones, developers were able to select specific sites. This zoned approach was facilitated by better data, increasing stakeholder consultation, improved interaction with the TSO (National Grid), strategic plans and planning tools. Round 3 also covered a much larger potential addition of offshore wind capacity. For example, zones were identified through the application of spatial planning tools (i.e. the MaRS Tool developed by the Crown Estate).

3.3.3.3 AWARDING OF TRANSMISSION ASSET RIGHTS

Once awarded a CfD, projects undergo commissioning and construction of both the generation site and transmission infrastructure. At this stage, OFGEM, the UK regulator, starts the process to sell and license the offshore transmission assets to an independent Offshore Transmission Owner (OFTO). This involves assessing the value of the assets and a tendering process based on bidding of a project-specific revenue stream. Importantly, this differs to the onshore transmission, which is a regional monopoly regime dominated by three entities.

Onshore grid access responsibility initially lay with the **developer**. The developer was responsible for:

- Securing a connection agreement and agreeing on onshore grid reinforcements.
- Designing and building the transmission connections.
- Operating and maintaining the transmission assets.

Initially, for the early rounds of offshore wind development, each developer was responsible for consenting, licensing, constructing and maintaining all of the grid connection assets required for its project. There were few alternatives other than for developers to operate the offshore cables and other connection infrastructure necessary to connect to the onshore electricity networks.

Since 2009 the third party Offshore Transmission Owner (OFTO) regime has been in place. Under this regime, the OFTO can either build or operate the transmission assets, or once the developer has constructed the assets the OFTO will take on the operation and maintenance of the transmission assets. There are three OFTO models, as explored below. However, to date all transmission assets have been built by the developers:

Early-build approach. The operator of the offshore transmission system is responsible for planning, consenting, construction, operation, and ownership of the link, including decommissioning.

Late-build approach. The operator of the transmission system is responsible for the construction, operation, and ownership of the link, including decommissioning.



Generator-build approach. The plant developer builds the connection system, and the transmission system operator is responsible for its operation and ownership, including decommissioning. To date, this is the only procedure used⁵⁵.

OFTO regime explained - an asset-based licensing approach: In the UK, OFTOs take responsibility for offshore transmission assets under long-term licenses. These are underwritten by the regulatory framework⁵⁶. OFTO assets link offshore generation sites to the onshore network and can include items such as offshore substation platforms, subsea export cabling and onshore cabling, an onshore substation, and the electrical equipment relating to the operation (e.g. transformers, communication equipment, etc.).

To date 15 transmission assets have been allocated across the first three tendering rounds, estimated at £2.9bn worth of investment to date and will represent 4.4GW of power that will be transmitted through these transmission cables. 14 of these assets are now operational, with availability estimated at over 98% across these assets⁵⁷. The third tender round has recently been completed, with a fourth currently live. The fifth round went live in Q4 2016 and will be the largest round since the first tender round, with the total value of the transmission assets in the fifth round estimated at £2bn. Assets being tendered out include 402MW Dudgeon, 336MW Galloper, 573MW Race Bank, 400MW Rampion and the 660MW Walney extension projects⁵⁸. It is expected that the sixth tender round will include Beatrice, East Anglia 1, Hornsea One, and Nearth Gaioth⁵⁹, all of which have secured CFDs⁶⁰.

Key principles of the Regime:

- The generator cannot be the OFTO. Moreover, neither can National Grid be OFTO
- Offshore connections exceeding 132 kV from the Renewable Energy Zone and the territorial sea adjacent to Great Britain require an offshore transmission license.
- Companies bid for an OFTO license which entitles them to a regulated rate of return on the costs of building and or operating the networks. The license is obtained through a competitive tender process which is governed by specific tender regulations.
- Building and or operating the networks. The license is obtained through a competitive tender process which is governed by specific tender regulations.

Revenue Stream: The OFTOs are provided with a fixed 20-year revenue stream (subject to performance delivery) in return for operating, maintaining and decommissioning the transmission assets. The revenue stream is unrelated to the performance of the generating assets. In this sense, the generator is responsible for the generation of electricity and the OFTO for its transmission to shore. The revenue stream is funded through the

⁵⁵EC. 2015. The regulatory framework for wind energy in EU member states. Available here: <https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/regulatory-framework-wind-energy-eu-member-states-part-1-study-social-and-economic-value>

⁵⁶ This differs from other countries where constructing and operating offshore electricity transmission assets is either the responsibility of the windfarm developer or the onshore transmission operator.

⁵⁷ See: <https://www.ofgem.gov.uk/ofgem-publications/99614>

⁵⁸ See: <http://renews.biz/104399/fifth-ofto-sale-nears-kick-off/>

⁵⁹ Noting this project has since experienced a number of setbacks, which may prevent deployment.

⁶⁰ See <https://www.ofgem.gov.uk/ofgem-publications/99614>



provision of transmission charges (Transmission Network Use of System Charges – TNUoS) that the wind farm has to pay to the GB NETSO. It should be noted that the UK follows a non-discriminatory connection regime for connecting renewables to the grid.

3.3.3.4 EVOLUTION OF THE REGIME

The OFTO Regime was designed in two phases: The Transitional Regime, for projects which could achieve an agreed stage of development by March 2012, and the Enduring Regime which applies to all subsequent projects.

In the Transitional Regime, developers construct the necessary transmission assets which are then sold to an OFTO appointed through Ofgem's tender process. The role of the OFTO is, therefore, to finance, own and operate an asset that has been constructed by the developer.

The Enduring Regime offers design and construction opportunities for the OFTO. Offshore developers have the flexibility to choose whether they or an OFTO design and construct transmission assets ('OFTO build' versus 'Generator build'). Regardless of the party selected for construction, an OFTO will be responsible for ongoing ownership and operation of the assets.

In conclusion, the historical approach to grid access responsibility was with the developer and has transitioned to a **third-party** approach. Moreover, the grid connection costs in the UK can be considered to be **shallow**.

Steps for awarding transmission assets include:

- The generation site developer requests OFGEM to commence a tender exercise, specifying developer build or OFTO build.
- OFGEM publishes a notice of its intention to commence a tender exercise for all qualifying projects. Detailed Tender Rules and the cost recovery methodology are published by OFGEM.
- Pre-qualification stage to determine qualifying bidders.
- Qualification to tender stage to determine the bidders that will be invited to participate in the invitation to tender stage.
- ITT stage to determine which qualifying bidders will become the preferred bidder or reserve bidder for each qualifying project.
- Successful bidders are granted the offshore transmission license

3.3.3.5 REASONS FOR CHANGE

- Increase competition: Initially for the early rounds of offshore wind development, each developer was responsible for consenting, licensing, constructing and maintaining all of the grid connection assets required for its project. There were few alternatives other than for developers to operate the offshore cables and other connection infrastructure necessary to connect to the onshore electricity networks. When looking to pass on these assets to another body, there were few other alternatives than National Grid.

- Responding to the EU: The UK government and OFGEM responded to the European Commission's desire to unbundle offshore ownership of UK electricity transmission infrastructure from generation and supply by developing the OFTO licensing approach.
- Reducing Costs: By granting licenses for new offshore transmission assets through a competitive tender process, regulators expect that generators are partnered with the most competitive players in the market. With the anticipated substantial growth of offshore wind, the overarching goal is to provide additional value for money for consumers through an open and competitive approach to ensure generation assets are connected to the grid in a cost-effective and efficient manner.
- Change of approach on generator build: The first aspiration under the OFTO regime was for OFTOs to take on the majority of elements linked to transmission, including the construction of the assets. However, during 2011 and 2012, OFGEM consulted on the option to continue to allow the generator to build the assets, as per the transitional regime resulting in a formal statement on the future generator build tenders in 2013.

Connecting to the onshore grid

National Grid allocates transmission grid capacity on a 'first come first served' basis, taking into account that some projects require onshore re-enforcement. Connection offers are made on the condition that the required transmission reinforcement works are completed. In the UK developers need to apply to the system operator for a grid connection agreement. National Grid then applies to the relevant Transmission Owner who will assess if reinforcement is required to connect the offshore wind farm, including local and strategic requirements. The developer must then wait for these reinforcements to be completed before it can connect its assets. There is no set time for this reinforcement to take place and the developer can, therefore, be subject to significant delay. For example, developers in Scotland have had to wait over five years because the connection requirements triggered extensive planning processes.

It should be noted that connection requirements differ according to the size of the 'transmission connected generation' (large versus medium versus small), although due to the large size of offshore wind they all follow the same steps. Also, while the majority is connected to the transmission system, they can also be connected to the distribution system. Directly connected generation requires a bilateral connection agreement (BCA) and a construction agreement with National Grid (CONSAG). Technical and commercial arrangements within the contract will depend on the peak MW output if the connection is made directly to a distribution network a bilateral embedded generation agreement (BEGA) or a bilateral embedded license exemptible large power station agreement (BELLA) is required.

Where the connection point is not obvious for offshore wind on interconnectors, National Grid will work with the developers through a process called 'Connection and infrastructure options note' (CION) to identify the least cost point to connect the offshore transmission. This process will involve establishing a six-figure grid reference to pinpoint the exact connection point, noting this can be directly onshore or further inshore.

3.3.3.6 FUTURE OUTLOOK

OFGEM consistently assesses and consults on changes and improvements to the scheme. These cover design options such as cost assessments and benchmarking, indexation of the licenses, modifications to the transmission license and mechanisms for paying the availability incentive bonus.

In practice, the aim for a transition from generator build to OFTO build of the transmission assets has not occurred because generators mainly perceive the transmission assets as key to the viability of their projects and are reluctant to bear the risk of a third party.

3.3.3.7 SUMMARY

Table 6: Summary of the UK's approach with respect to the three dimensions

Dimension	Strategy	Approach	
		Historic	Current
Locational Requirement	Open-door	✓	
	Zoned		✓
	Single-site		
Grid access responsibility	TSO		
	Developer	✓	
	Third party		✓
Grid connection costs	Super shallow		
	Shallow	✓	✓
	Deep		

3.3.4 SWEDEN

Sweden decided in 2003 to expand the use of renewables and established a goal of increasing the annual energy from renewables by 10 TWh compared to 2002 by 2010. This goal was reviewed in 2006 and rose to 17 TWh more than 2002 by 2016. The target was again revised in 2010 to 25 TWh. In 2009, Sweden adopted a national planning framework for 30 TWh of wind power by 2020, indicating a strong desire to incorporate the wind in the generation matrix (Tonderski, 2013).

Consequently, a significant expansion in the installed capacity of wind generation has occurred over the past decade. The installed capacity of the wind in the generation mix has grown from about 600 MW in 2006 to 6000 MW in 2015. However, offshore wind power makes up a small fraction of this capacity. As of 2016, only 201 MW of the installed capacity of wind farms were offshore. Figure 18 shows the development of offshore wind capacity in Sweden.

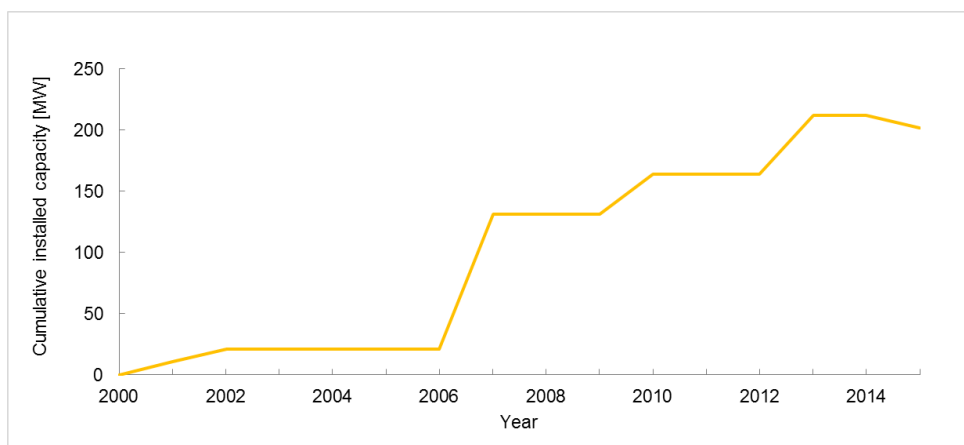


Figure 18: Offshore wind development trends in Sweden

In all Sweden has five offshore wind farms in operation, with a total of 86 turbines. Compared to other neighbouring countries such as Germany, Denmark, and the UK, not only has the development of offshore generation has been slow in Sweden, but the country has already seen the first decommissioning of an offshore wind farm in 2015. The wind farm Yttre Stengrund was completely dismantled due to its old technology, high maintenance costs and high cost for substituting the generating units (Vattenfall, 2016).

3.3.4.1 AN OPEN-DOOR APPROACH TO THE SITING OF OFFSHORE WIND FARMS

In Sweden, the investor can present a proposal to develop an offshore wind farm in one of the so-called National Interest Areas for wind farm development. Since 2004 the Swedish Energy Agency is responsible for defining areas on land and at sea with particularly good wind conditions that should be of national interest for wind power generation. The last update of this zoning was carried out between 2010 and 2013. Today, there are 313 areas of national interest for wind farms, of which 284 areas are onshore and 29 at sea and in lakes. However, it is possible to build even outside areas of national interest, if a trial proves the area is adequate or if the municipality recognises the area as appropriate for its general plan (Swedish Energy Agency, 2016). It can be said that in Sweden an **open-door** approach is utilised for the development of offshore wind generation.

In Sweden, there is no “one stop shop” approach for clearances. Therefore the developers’ proposal has to go through a process of permitting that involves several agencies (Jacobsson et al., 2013). This has an adverse impact on the attractiveness for new projects, as not only do costs increase, but there is also a severe risk of delay, or even worse, denial of permission by an agency. These risks are illustrated by a 2.5 GW offshore project that was denied permission to due to opposition from the military in 2016, even though the area is identified as of national interest (Hirtenstein, 2016; Radowitz, 2016a).

According to Söderholm and Pettersson (2011), the key legal obstacles for installing a wind power plant in Sweden come from (a) the permitting procedure for environmental concession and (b) the territorial planning system.

The permitting process, defined by the Environmental Code, is not as clear as a legal rule would be. This makes the process possibly longer and gives incentives for appealing. The permitting process tends to have more requirements for onshore projects than for offshore projects. In the case of offshore projects, the developer must have two permits (with synchronised trial) as well as an environmental impact assessment. The permits are for hazardous environmental activity (EHA) and hydraulic (water) operation (WO) (Söderholm and Pettersson, 2011). If the wind power installation is outside the Swedish territory, but within the Swedish economic zone, only one permit is required.

On the other hand, the territorial planning might be the source of conflicts of interest, as the process of defining “national interests” is not coordinated among institutions and not strictly binding. These areas are defined by the Swedish Energy Agency based on the wind profile of the region. Once the area is defined, it “shall, to the extent possible, be protected against measures that may be prejudicial to the establishment or use of such sites” (The Swedish Environmental Code, Chapter 3, Section 8). The binding is soft, and the rules from the Environmental Code do not provide guidance in case the same area is also of national interest for another purpose (e.g., nature conservation) (Söderholm and Pettersson, 2011).

3.3.4.2 CONNECTION RESPONSIBILITY

Concerning the priority of connection for renewable generation, Sweden applies a non-discriminatory policy (González and Lacal-Aránegui, 2016), meaning renewables are not entitled to priority of connection over conventional generators.

The owner of the offshore power plant is responsible for paying for the transmission cable, and the connection to the onshore network (Energinet.dk, Svenska Kraftnät, 2009; Meeus, 2015; Swedish Energy Agency, 2015) and therefore, the Swedish case could be considered a developer approach. However, it is important to note that the Swedish Electricity Law⁶¹ prohibits production and transmission of electric power within the same company. Although the connection is built by the developer, in operation phase, the generation and the grid activities must be separated.

This legal unbundling requirement can be illustrated with the Lillgrund wind farm, the biggest in Sweden (48 turbines, 110 MW installed). In this project, Vattenfall Vindkraft AB is the company that owns and operates the power plants while Lillgrund Elnät AB is a subsidiary company to Vattenfall Vindkraft AB that owns and operates the electric network and transformer platform (Söderberg and Weisbach, 2008). “However, technicians working at Lillgrund are working with both the electrical system owned by Lillgrund Elnät AB and the wind turbines owned by Vattenfall Vindkraft AB” (Söderberg and Weisbach, 2008, p. 16(25)). Thus, due to this process of unbundling of the generation and transmission business, the grid access responsibility is evolving into a **third party** controlled approach.

⁶¹ Swedish electricity law (1997:857), 3rd Chapter, 1a



In Sweden, the grid connection costs are considered to be **deep** (ENTSO-E, 2015d). Note that in the “Guidance of the National Grid” (Svenska Kraftnät, 2016), the TSO states that the connection fee shall be equal to the total increase in investment by the Swedish power grid as a result of the connection. That includes the addition of new lines, new stations, upgrading of existing power lines, replacement of a switching device or a transformer (Svenska Kraftnät, 2016).

3.3.4.3 FUTURE OUTLOOK

The Swedish Energy Agency has recently elaborated a comprehensive report aiming to strengthen support mechanisms (Swedish Energy Agency, 2015). One of the proposals is to have a tender procedure for sliding premium support. This mechanism would be based on the electricity price. The higher the price, the lower the level of support required. However, this is still just a proposition from the Swedish Energy Agency. Another form of support already is the end of deep connection fees. A recent agreement involving the main political parties in Sweden just stated that "Connection fees to the national grid for offshore wind should be abolished." (Weston, 2016).

3.3.4.4 SUMMARY

Table 7: Summary of the Swedish approach with respect to the three dimensions

Dimension	Strategy	Approach
		Current
Locational Requirement	Open-door	✓
	Zoned	
	Single-site	
Grid access responsibility	TSO	
	Developer	
	Third party	✓
Grid connection costs	Super shallow	
	Shallow	
	Deep	✓

3.3.5 WHAT DO THE REMAINING COUNTRIES DO?

3.3.5.1 THE NETHERLANDS

Historically, the Netherlands followed an open-door approach for the development of offshore wind farms. However, the wind farms were restricted to two zones that were identified under the National Water Plan. New legislation was introduced in the Dutch parliament in 2015 to encourage the rapid development of offshore wind. According to the new regulation, in the coming years, the Netherlands will move to a single-site approach to define the locational requirements for providing RES support. The sites have been designated in three zones. However,

various aspects of the wind farm such as location and offshore cable route will be tightly defined. The grid access responsibility will solely lie with the Dutch TSO Tennet, and the grid connection costs would be super shallow⁶².

3.3.5.2 BELGIUM

Since 2004 in Belgium, a zoned approach has been utilised to define the location requirement for providing RES support (Brabant and Degraer, 2010). The grid access is the responsibility of the wind farm developer. However, this is expected to change to a TSO led approach by 2018 with the TSO funded 'socket at the sea' initiative (Fitch-Roy, 2015). In the context of the grid connection costs, the Belgian TSO has been responsible for bearing up to one-third of the capital cost of building the offshore grid for the current projects (González and Lacal-Arántegui, 2016).

3.3.5.3 NORWAY

Norway appears to have a low development of the offshore wind industry as compared to its European neighbours, which to a certain extent could be attributed to its high hydro-electricity potential. It appears that Norway follows an "open doors" approach for defining locational requirements for RES support. Currently, there are no commercial offshore projects that require connection to the onshore network. As there is no clarity in the regulation regarding the grid access, responsibility lies with the developer, and consequently, the cost of connecting to the grid would be borne by the developer. Norway applies shallow connection charges (ACER, 2014a).

3.4 INSIGHTS

In this section, we compare the evolution of the regulatory systems for offshore wind in the four EU member states that have been studied in this report over time. This comparison provides us with interesting insights into the level of coherence between different national policies and whether any clear preferences towards particular strategies have developed.

3.4.1 LOCATIONAL REQUIREMENTS FOR RES SUPPORT

Table 8: Comparison of locational requirements for RES Support in the countries under consideration.

<i>Valid for 2017</i>	Germany	Denmark	UK	Sweden
Open-door				✓
Zoned			✓	
Single-site	✓	✓		

In two member states, namely Germany and Denmark, a single-site approach to locational requirements for RES support has been implemented. While Denmark has consistently followed this approach, Germany has evolved their regulatory structure towards it over time. In the UK, a zoned approach has been preferred. (See Table 8).

A single-site approach has an inherent advantage from the perspective of the party responsible for providing grid access as it has the information regarding the precise location of the project well in advance, making it possible

⁶² For more details on the super-shallow approach in the Netherlands, please refer to the WP 7.1 Intermediate report: Legal Framework for offshore grid planning

to plan the necessary offshore infrastructure more effectively. A similar advantage is presented by a zoned approach. However, the exact location of the wind farm within the zone is uncertain until the developer decides and this may shorten the lead time available for planning and connect the offshore line as compared to a single-site approach.

Sweden (and Norway) continue to use an open-door approach to allocating offshore wind farm locations. The developer proposes a site for construction of the wind farm. This approach has numerous inherent planning risks that begin with approvals from all relevant agencies. These risks in Sweden are illustrated by the example of a 2.5 GW offshore project that was denied permission to due to opposition from the military in 2016.

3.4.2 GRID ACCESS RESPONSIBILITY

Table 9: Comparison of Grid Access Responsibility in the countries under consideration

<i>Valid for 2017</i>	Germany	Denmark	UK	Sweden
TSO	✓	✓		
Developer				
Third Party			✓	✓

Some interesting insights develop while comparing the grid access responsibility dimension for the four case studies (See Table 9). In Sweden, legal unbundling of generation and transmission is a regulatory requirement. Therefore, two separate legal entities are responsible for energy production offshore and the transmission of this power to the onshore network. In theory, this would indicate that the Swedish approach towards grid access responsibility is third-party-led. However, as can be observed from the example of Vattenfall, the ownership of the generation and transmission companies is not fully unbundled. Thus, for all purposes, the developer remains responsible for the grid access. On the other hand, in the UK, complete ownership unbundling is required. Therefore, grid access responsibility is clearly led by a third party.

While both countries have a third-party approach, it is apparent that depending on the regulatory framework there is a variance in the level to which the two entities, wind farm developers, and transmission operators, are independent of each other. Whether, and to what extent such a variance would impact the development of the offshore transmission infrastructure remains to be seen.

On the other hand, Germany and Denmark have an approach in which the TSO is responsible for grid access. Also in Belgium and the Netherlands, this approach is followed.

3.4.3 GRID CONNECTION COSTS

Table 10: Comparison of Grid Connection Costs in the countries under consideration.

<i>Valid for 2017</i>	Germany	Denmark	UK	Sweden
Super shallow	✓	✓		
Shallow			✓	
Deep				✓

The super shallow approach has consistently been followed in Denmark, at least for the tendered wind farms. It is observed that other EU member states, such as Germany and the Netherlands, are also moving towards such

an approach. As well in the UK, where a shallow cost approach has been applied in the past, the transition to a super shallow OFTO (third party) financed approach is expected in the coming years. (See Table 10).

A deep connection cost approach may make it unattractive for developers to invest in offshore wind projects as there may be substantial added costs due to onshore grid reinforcements that may be needed at the onshore connection point. In an extreme case of deep connection cost regime such as in Sweden (and Norway), the developer may not have sufficient incentive to invest in grid reinforcements, which often have a lumpy nature. In that case, smart connection contracts, such as a TSO offering interruptible capacity⁶³, might be a solution (Anaya and Pollitt, 2014).

From our case studies, we can see that countries are in the process of shifting toward a super-shallow approach. Weißensteiner et al. (2011) even argue that in that super shallow connection charges are socially more optimal than shallow connection charges (in the case coordinated planning procedures for the siting of the wind farms are in place). Their main argument is that capital costs are higher for offshore wind power producers, which are exposed to comparatively high financial risks, in comparison to the regulated monopolistic transmission grid operator.

3.5 CONCLUSIONS

In this chapter coordination between onshore and offshore grid planning has been discussed. It was described how different countries adjacent to the North Seas have divergent approaches towards the regulation of offshore grids. The countries analysed were Germany, Denmark, United Kingdom and Sweden. In each case study, the evolution of the regulatory framework for the offshore-onshore connection has been presented. The assessment of coordination was based on three main dimensions, namely location requirements for offshore wind farms, onshore grid access responsibility, and grid connection costs.

The evolution of the analysed regulation in the four countries shows that the approaches varied not only between the countries but also over time. Germany had serious problems with delayed offshore grid connections in the past, which led to an increased proactivity in planning. Today, planning the offshore cables precedes allocating renewable support to wind farms and no longer vice-versa. Denmark consistently applied a single-site TSO-led scheme and introduced a tailor-made regulation for near-shore wind farms. Sweden seems to have remained stable regarding the assessed dimensions of offshore regulation. However, the Swedish energy agency has proposed an overhaul of the system, which is currently being discussed. The UK has implemented a unique approach, in which a fully unbundled independent third party builds (optionally), owns and operates the offshore connection. However, the UK too is moving towards a more coordinated planning approach.

⁶³ Generators may prefer to be curtailed at certain moments as it might be more cost effective than paying for the full network reinforcements.

4 OFFSHORE GRID PLANNING III: PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

4.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 19.

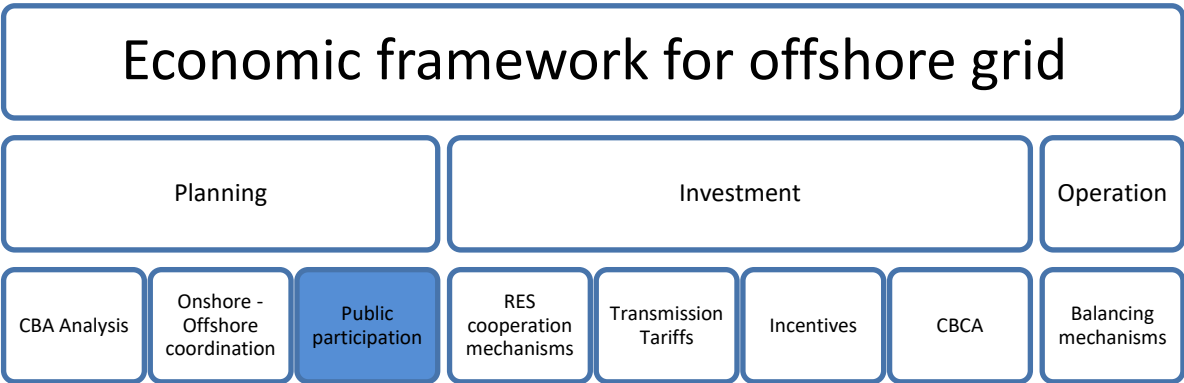


Figure 19: Illustration of the position of this chapter in the overall report structure.

One of the most critical aspects of the successful development of the offshore infrastructure, be it the wind farm itself or the related grid infrastructure, is the participation and support of the local population. The issue of public opposition to offshore wind projects is already recognised as one of importance by EU member states. For example, the energy white paper of the UK government 2003 highlights this issue as a significant barrier to reaching their emission reduction goals (DTI, 2003; O’Keeffe and Haggett, 2012).

Public opposition to a project can lead to a significant increase in costs and delays in construction (Wiersma et al., 2011). While public participation has several advantages, several concerns are presented as reasons for limiting the level of public involvement in the development of offshore wind infrastructure projects. The following table shows a list of advantages and concerns identified by Sorensen et al., (2002).

In the context of onshore wind power development, the issue of public opposition has been discussed widely in the literature (e.g.: Ladenburg, (2008); Pasqualetti et al., (2002)). Enlarging incentive regulation to improve public awareness and trust in electricity transmission infrastructure development has been discussed by Bhagwat et al., (2018a, 2018b). Offshore wind development has by many (e.g: Duffin et al., (2002); Haggett, (2011); Henderson, (2002); Henderson et al., (2003); Ladenburg, (2010); Marsh, (2001); Still, (2001); Tong, (1998c)) been considered less problematic from this perspective. However, various studies have indicated otherwise. Several case studies of public opposition to the development of offshore wind infrastructure have been highlighted in the literature, (e.g: Devine-Wright and Howes, (2010); Ellis et al., (2007); Futák-Campbell and Haggett, (2011); Haggett, (2008)).

Table 11 presents the various advantages and concerns regarding public participation in offshore wind infrastructure development project as described by Sorensen et al., (2002).

Table 11: Advantages and concerns regarding public participation in offshore wind infrastructure development project (Sorensen et al., (2002)).

ADVANTAGES	CONCERNS
Better awareness of public concerns	May have a negative impact on the situation
Lower possibilities of misunderstandings	The public participation process may be inefficient
Greater cooperation and understanding between different stakeholders	It may broaden the scope of the problem
Improvement in balancing several aspects during the planning of the project	Impossible to appease everyone.
Development of greater level of trust	

This chapter is structured as follows. In the next section, we delve deeper into understanding the public perception of offshore wind infrastructure development by looking at various factors that frame the public perception towards a particular project. In the second section, we discuss the concept of public participation and public engagement in the planning of offshore wind infrastructure projects. In the third section, two case studies of offshore wind projects where the local communities and people from the affected regions have actively participated in the development of the offshore wind projects are presented. The chapter ends with a brief conclusion section.

4.2 UNDERSTANDING PUBLIC PERCEPTION TOWARDS OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

In recent times, there has been an increase in the interest in understanding the impact of public opposition to offshore wind infrastructure projects. This interest is reflected in the regular publication of literature on this topic. While most of the research is focused on the development of the wind farm itself, many aspects discussed may still be relevant to the development of the offshore wind infrastructure including the necessary transmission network. In this section, we identify some key frameworks and parameters that are defined in the literature as building blocks for the understanding of the public perception of offshore wind projects and to mitigating the risk of public opposition.

In an effective public engagement program, it is essential to analyse and understand the key drivers that are the foundation for framing the opinion of local communities and other relevant stakeholders in the project affected areas with regards to the given project.

Several studies have been conducted to define the basis for public perception (and opposition) to wind farms. Wolsink, (2007) contends that the visual impact is the main reason for public opposition to wind development. This reasoning is supported by Warren and Birnie, (2009) in their work on offshore wind farms in Scotland. Devine-Wright, (2009) present the threat to one's "place identity" (defined as an attachment/familiarity to a place (Manzo,

2005)) as another reason for public opposition. Other causes stated in literature are a lack of information on the project (Wolsink, 1996) and a low level of public involvement in the planning process (Bell et al., 2005).

In their paper titled “Understanding public response to offshore wind power” Haggett, (2011) present a set of factors (summarised below) that need to be taken into consideration while discussing the public response to offshore wind projects. These factors provide a useful starting framework for a global understanding of the issues of importance in the context of public opposition and in turn would aid in developing effective strategies for mitigating (or minimising) it. In their paper, the authors also observe that these factors are equally relevant to onshore and offshore wind development.

- **Visual impact:** The visual impact factor has always been identified as a top priority issue with regard to public opinion on projects such as wind farms (Kempton et al., 2005; Ladenburg and Dubgaard, 2007). Initially moving wind energy development offshore was expected to solve this issue. However, as of now, even the furthest viable sites for offshore wind farms would still have a visual impact. Studies have shown that even a minor visual impact has a strong negative public perception (Sorenson et al., 2001).
- **Local context and place attachment:** A robust link is observed between the historical and social context and the public perception of the development of offshore wind projects. An example of this in the UK is presented by Devine-Wright and Howes, (2010) comparing two seaside towns in the UK. The first town under consideration in their study was Llandudno which is popular with tourists. On the other hand, the counterexample was of Colwyn Bay which can be described as an under-developed town. Development of offshore wind farms in the Llandudno area was evaluated far more negatively by the residents of this town as it threatened the natural beauty of the area, while the inhabitants of Colwyn Bay viewed it positively as they expected to reap economic benefits from such projects.
- **The disjuncture between the local and the global:** There appears to be a disconnect between the understanding the risks and benefits of offshore wind development from a global perspective vis-a-vis a local perspective. At a macro level, offshore wind power would be extremely beneficial in fighting climate change and reducing GHG emissions. However, at a micro level various factors such as direct benefit to local communities, harm to the local environment, sea life, birds, impact on local fishing, recreational activities etc., play a significant role in swaying public opinion (Bell et al., 2005; Firestone et al., 2009; Firestone and Kempton, 2007; Gray et al., 2005; Haggett, 2008; Hartnell and Milborrow, 2002; Jay, 2010; Ladenburg, 2009, 2008). Haggett, (2008) capture this effect by introducing a theoretical framework consisting of two gaps: the “social gap” which is the difference between the strong support for wind but small success in deployment (at that point) and the “individual gap” between a single person who supports wind power in general but actively opposes a particular wind energy project.
- **Relationship with outsiders:** Another key observation has been that local community groups and government projects face much less public opposition as compared to large multinational energy companies. There appears to be mistrust in the local communities of large “faceless” multi-national wind farm developers.

On the other hand, local authorities or local community groups are perceived to have a better understanding of the local situation. This may be a driving force for a more positive attitude towards them as compared to the multi-nationals (Gross, 2007; Haggett, 2011, 2008; Jobert et al., 2007; van der Horst, 2007; Wong, 2010).

- **Planning and Participation:** Gross, (2007) determine that faith in the “fairness” of the decision-making process and the people in charge of this process with regards to offshore wind development project has a substantial impact on the acceptability of the project. The negative externalities due to the perception that the public has no say in the development have been studied by (Devine-Wright, 2011; Devine-Wright and Howes, 2010; Haggett, 2008). Thus, greater public involvement at various steps of the decision-making process can have a significant positive impact on public perception (Kempton et al., 2005).

4.3 UNDERSTANDING PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

In the previous section, we saw several factors that impact public perception in the context of offshore wind power infrastructure development. Although wind energy is perceived positively at a global level, historically not only onshore wind but also some offshore wind power projects have faced public opposition. Thus it is clear that ensuring public participation is imperative for successful development and deployment of the offshore wind infrastructure in the coming years. In this section, we discuss the concept of public participation. Initially, we present a broad overview of this topic by introducing Friedman and Miles’s “stakeholder ladder.” Then we further narrow the scope to an offshore wind infrastructure development context.

Figure 20 illustrates the stakeholder ladder that has been developed by the different levels of stakeholder by Friedman and Miles, (2006). The “ladder” has been created to present the degree or level of stakeholder involvement in the development of any project. Understanding the different steps in the ladder will aid in providing a better insight into the extent of engagement that has occurred in the offshore wind context and avenues for further improvement.

The highest degree of engagement is the proactive or trusting level. At this level, the stakeholders are made to participate in the decision-making process actively. At the highest step, the stakeholders have a significant representation in decision making (Stakeholder control). In the second phase, the stakeholders have a minor representation (Delegated power). When a joint decision-making process is used, it is defined as a ‘partnership’ while when limited power of decision is ceded to the stakeholders, it is called collaboration. The lowest level in proactive step is ‘involvement’ in which only limited support is provided by the stakeholders.

The next lower level in the ladder is “Neutral” consisting of four steps. The highest of these is ‘negotiation’ which is similar to ‘partnership’, however they differ in the level of conformity by the organisation. The next step is ‘consultation’ in which the stakeholders can advise, however these recommendations are not binding. In ‘placation,’ the organisation listens to the perspective of the stakeholders, however, does not provide any binding assurance. The lowest step in this level is ‘explanation’ in which the stakeholders are educated about the project.

The third and lowest level of the ladder is called the 'autocratic' level consisting of three steps. The first step (informing) is similar to 'explanation' but with less effort. The second (therapy) and third (manipulation) steps are superficial attempts at engagement with the extreme situation being that of misleading the stakeholders.

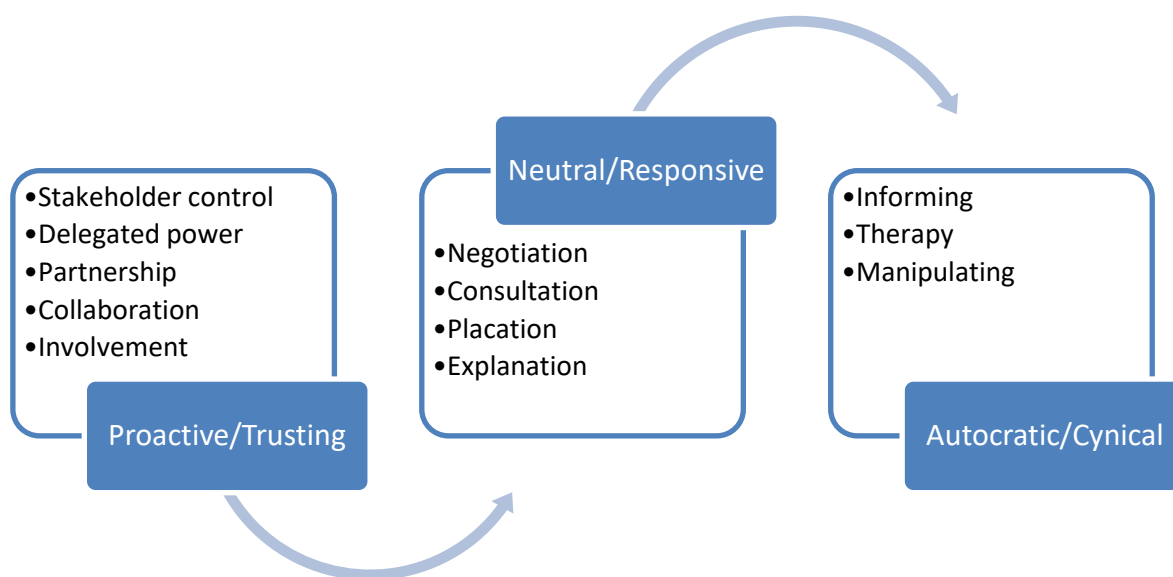


Figure 20: Levels of stakeholder participation (Based on Friedman and Miles, (2006)).

Sorensen et al., (2002) analyse the concept of public involvement in offshore wind infrastructure development in further detail by providing a clear framework for forms (degree) of public participation. The authors contend that that in the context of offshore wind infrastructure development, public involvement is possible using three different approaches namely;

- **Information:** In this approach, the relevant stakeholders (public) are engaged by the developer by informing them about the ongoing development. This method may be considered either in the 'informing' or 'explanation' step from the perspective of the above described "stakeholder ladder."
- **Planning participation:** In this approach, people are encouraged to participate in the decision-making process. These could consist of the bottom two steps in the proactive level and the top step of the neutral degree in the "stakeholder ladder."
- **Financial participation:** This is the highest level of involvement in which the public has a financial involvement in the project and thus in the decision making. Financial involvement may be considered as the top three steps of the "stakeholder ladder."

However, the authors (Sorensen et al., (2002)) also mention that the wind power developers opt for a minimum level of public engagement that they are required to undertake. This may usually consist of passively informing

the public rather than allowing them to engage in decision-making actively. However, counterexamples such as Denmark do exist where a strong local public involvement in wind development has been encouraged.

4.4 EXAMPLE OF PUBLIC PARTICIPATION IN OFFSHORE WIND INFRASTRUCTURE DEVELOPMENT

High financial participation and planning participation by the public has occurred in several renewable generation initiatives (including onshore wind power) across Europe. The importance of public participation in minimising public opposition has been discussed in depth in the literature (Bell et al., 2005; Gray et al., 2005; Haggett, 2008; Wolsink, 1996). However, as discussed in the earlier section, in most cases, public participation in the development of offshore wind projects is minimal or limited to a consultation level. Nevertheless, there are some instances in which the public has been successfully encouraged to participate in the financing and planning of offshore wind projects. Thus, much can be learned from these experiences. In this section, interesting case studies from the literature are presented.

4.4.1 PUBLIC PARTICIPATION IN THE DANISH OFFSHORE WIND FARM DEVELOPMENT

Denmark is one of the leading countries in onshore as well as offshore wind power development. Denmark has the third largest capacity of offshore wind farms in the world (EWEA, 2016). In fact, the first ever demonstration project on the use of offshore wind turbines for generation of electricity was built off the coast of Denmark in 1991 at the Vindeby offshore wind farm. This project gave impetus to the construction of more such demonstration projects, finally leading to the world's first two commercial offshore wind farms: Horns Rev I (160MW) commissioned in 2002 and Nysted (165MW) commissioned in 2003 (Danish Energy Authority, 2015). As of 2014, Denmark has an offshore wind generation capacity of roughly 1.27 GW (EWEA, 2016).

Apart from being a pioneer in the development of wind power capacity, Denmark has also been at the forefront of enabling public participation in wind power development. Since the start of the wind revolution in Denmark, social acceptability has been considered a critical aspect of its development. This includes responsible and holistic site selection procedures. Local communities are encouraged to participate in all aspects of wind infrastructure planning be it the planning of a local wind farm project or defining of zones for offshore wind farm development. The main approaches for public involvement consist of conducting public meetings, soliciting written statements (online and on paper) from various stakeholders regarding their concerns and suggestions. It has been observed that this "bottom-up" public participation has led to a significantly higher public acceptance levels for such projects in Denmark (Szarka, 2007). The Energy Policy Agreement of 2008 added more initiatives for the further promotion of local acceptance.

One unique aspect of the Danish wind industry is that most onshore Danish turbines are owned by neighbourhood cooperatives. This can be considered as one of the key driving forces for greater social acceptability of wind energy in Denmark (Danish Energy Authority, 2015). As of 2001, it was estimated that more than 150,000 households held ownership shares for wind turbines (Meyer, 2007). It has been observed that this has led to a



considerable reduction in the impact of NIMBY and other concerns of the locals regarding the installation of wind turbines. The cooperative approach also provides the individuals and local communities to participate in and support the development of offshore wind projects.

Recently, this public involvement has been extended to offshore projects too. Furthermore, the Danish government has provided additional incentive for public participation in near-shore projects that are expected to be developed soon. The first six sites for near shore wind power development have been selected keeping in mind the favourable public sentiment in these regions towards wind development. Moreover, the developers are obligated to offer 20% share to residents and enterprise (however it is not necessary to achieve this objective). If the public ownership is 30% or more, a higher feed-in tariff will also be offered to the project.

4.4.1.1 MIDDLEGRUNDEN WIND FARM⁶⁴

The Middlegrunden offshore wind farm can be considered as one of the first examples of offshore wind energy projects with active public involvement. The wind farm is located roughly 3KMs off the coast of Copenhagen in Øresund strait that separates Sweden and Denmark. The facility is owned 50% by Dong Energy and 50% by the Middlegrunden wind turbine cooperative. The Middlegrunden wind turbine cooperative was formed in 1996 from an initiative by the Copenhagen Environmental and Energy Office (CEEEO) and local groups to harness the wind potential at this particular site demarcated in the Danish Action Plan for Offshore Wind (Sorensen et al., 2002). The cooperative has a membership of 8,500 people.

The initial application for the Middlegrunden offshore wind farm was made in 1996. This was followed by two rounds of public hearings that led to approval in principle in May 1999. The third round of public hearings on the EIA report was held between July and October 1999. The Danish Energy Agency approved the final permit in December 1999, and the construction was initiated in March 2000. The facility began production of electricity in 2001. Currently, the wind farm consists of 20 2MW wind turbines (Larsen et al., 2005; Soerensen et al., 2000; Sorensen and Hansen, 2002). The Northern 10 wind turbines are operated by Dong Energy and the remaining 10 by the Middlegrunden wind turbine cooperative. The statistics from the year 2016 indicate that the wind farm produced roughly 40GWh of electricity.

Initially, the proximity of the wind farm to the coast led to public concerns regarding noise. However, by effectively informing the public (for example: Arranging a visit to an existing offshore wind facility), these concerns were addressed. Many shareholders of the cooperative actively participated in the public hearing and supported the development of the project. Furthermore, the concerns of the stakeholders were also addressed by the developers. For example, in the beginning, the project was envisaged to consist of 27 wind turbines. However, after public criticism of the wind farm layout during the consultation. In reaction, the layout of the wind farm was modified which led to a reduction in the number of wind turbines from 27 to 20 2MW wind turbines (Jessien and Larsen, 1999).

⁶⁴ Based on Sorensen et al., (2002) and www.middelgrunden.dk

It is believed that the high level of public participation (financial participation as well as planning participation) was a strong driver for the low public opposition to this project. This makes it a good example of how a high level of public involvement could have a positive impact on the development of offshore wind energy projects.

4.4.2 PUBLIC PARTICIPATION IN THE UK'S OFFSHORE WIND FARM DEVELOPMENT

The United Kingdom has the highest installed capacity of offshore wind farms in the EU. Since 2000 when the first 4MW prototype was commissioned, a rapid increase in offshore wind capacity has been observed, especially since 2010. As of 2015, the UK has a total offshore wind installed capacity of roughly 5GW.

After a prototype 4MW test site in 2000, the UK commenced offshore wind farm development with 'Round 1' of site leases. Five pilot sites were developed from 2003 to 2008 with a total capacity of 390MW. The 'Round 2' of site leases consisted of a further 8GW of sites, mostly off the East Coast. Round 3 identified up to 33 GW of offshore wind development in the UK Renewable Energy Zone across 9 zones. In contrast to the first two rounds, zones in the third round were competitively tendered. At the same time, in Round 3, extensions were granted to Round 1 and Round 2 sites. The fourth tendering round is anticipated to take 18 months from start to finish, i.e. the Enhanced Pre-Qualification Document was made available in April 2016 and the final selection of the preferred bidder is anticipated in March 2017.

Participation of key stakeholders, local authorities and local communities at the earliest possible time during the development of new offshore projects is considered critical by the UK authorities (DECC, 2009). In the context of public participation in planning, the Planning Act 2008 makes it incumbent upon developers to engage and consult local communities, local authorities (including authorities in adjacent areas) and relevant stakeholders in the area affected by the offshore project. Consequently, the pre-application consultation for wind farm projects is now a compulsory element of the wind farm project development process (DCLG, 2013).

While making an application for the project, the project developer (or applicant) needs to submit a "statement of community consultation" developed jointly with the local authorities, outlining the strategy for engagement of local communities in the planning process. Eventually, the applicant is also required to submit a "consultation report" detailing the steps taken in the consultation process as well as the action is taken to address the concerns that were raised (DCLG, 2012). The guidelines for the pre-application consultation process including that for offshore wind farm development was first published by the Department for Communities and Local Government in 2009 and replaced by a new version in 2013 (DCLG, 2013).

Three cases of community engagement for offshore wind farm development in the UK have been discussed by Aitken et al., (2014) namely: Argyll Array, Triton Knoll, Gwynt Y Mor. In this chapter we describe the Triton Knoll case as an example of public engagement practices in the UK as described by Aitken et al., (2014).



4.4.2.1 TRITON KNOLL OFFSHORE WIND FARM⁶⁵

The wind farm project at Triton Knoll was awarded by the Crown Estate as part of the second round of tendering for offshore wind development in 2004 and has been classified as a Nationally Significant Infrastructure. The wind farm site is located roughly 32 km off the coast of Lincolnshire and 45 km from the north Norfolk coast. The project received its initial consent for the offshore array in July 2013, followed by the consent for the onshore electrical systems in September 2016⁶⁶. Originally the planned capacity of the wind farm was supposed to be 1.2GW. However, based on detailed technical and commercial viability studies undertaken by the developers in due course of planning, it was announced that the size of the wind farm would now be reduced to 900MW.

During the planning of this wind farm project, several statutory and non-statutory consultation steps were carried out by the project developers. In the first statutory consultation focused on the scope of the Environmental Statement. These long-drawn out consultations had a significant impact on the scope of the EIA and the project layout. This was followed in 2009 by a consultation on the Statement for Community Consultation (SoCC) with the local authorities. These consultations also had an impact on the transmission infrastructure development with regards to concerns from coastal residents about the location of onshore substations (leading to a reduction in potential locations for the substations). However, in 2010, due to the interjection of National Grid, the wind farm planning process was separated from the cable routing and onshore development planning. Thus, these issues were addressed separately. However, some local protest groups were formed to oppose siting of substations in their vicinity.

In the final pre-application consultation stage, further consultations were conducted with local communities, authorities and other prescribed bodies. The formal consultation period was also advertised via the internet. The community consultation was conducted with the objective of encouraging participation in the overall planning of the project by providing them with a platform to put forward their concerns as well as suggestions. Furthermore, a public exhibition was conducted at five locations onshore from where the wind farms could be visible. This also provided the developers with an opportunity to inform the visitors about the project and clear any misconceptions. Although not legally binding, the developers of the project promised to consider all the concerns while developing the final application. After the end of the formal consultation process, a final consultation on key issues was conducted to resolve any outstanding concerns. In the post-application period, further hearings of expert stakeholder and interested parties along with the opportunity for written comments on the application were facilitated. The consultation process led to modification in some aspects of the project.

4.5 CONCLUSIONS

In this chapter, the public participation and public opposition in the context of offshore wind infrastructure development are analysed based on current literature on this subject. Public participation will play a critical role in all aspects of infrastructure development, be it the wind farm itself or the transmission infrastructure. This chapter provides a deeper understanding of this issue to aid in developing more effective strategies for dealing

⁶⁵ Based on: Aitken et al., (2014) and <http://www.tritonknoll.co.uk/>

⁶⁶ Source: <http://www.tritonknoll.co.uk/>



with public concerns and ensuring greater public participation in all aspects of offshore wind infrastructure projects in the future.

In literature, several studies have been conducted to analyse the concept of public perception and the key factors that have an impact on how local communities and stakeholders perceive the development of a project. The five factors discussed by Haggett, (2008) namely; visual impact, local context and attachment, the disjuncture between local and global, relationship with outsiders, planning, and participation were described in greater detail. This framework appears to be relevant for developing an effective strategy for greater public engagement and participation.

At a global level, wind power is perceived positively. However, onshore wind, as well as some offshore wind power projects, have faced public opposition. Thus, it is imperative to ensure a high degree of public participation for successful development and deployment of the offshore wind infrastructure in the coming years. The various degrees of stakeholder participation has been presented in the literature by Friedman and Miles, (2006) in the form of a “stakeholder ladder”. In the context of wind power development and more stylised version has been presented by Sorensen et al., (2002). Understanding these structures would offer the reader a broader perspective on the current level of public engagement with offshore wind infrastructure development and gauge the scope for improvement to ensure even greater public participation in the future.

Two case studies of offshore wind projects where the local communities and people from the affected regions have actively participated in the development of the offshore wind projects were presented. The first case study was of the Denmark of the Middlegrunden offshore wind farm. 50% of the facility is owned by a wind farm cooperative. The second case study described is that of the Triton Knoll Offshore Wind Farm which is under development in the UK. The developers of this project conducted a robust public engagement program from a very early stage of the planning process. These two cases have been discussed to highlight examples where a high level of public participation has been successfully attained.

From an offshore wind infrastructure development context, a high level of public participation would have a positive impact on the public acceptability of such projects. To achieve this, the perspective of the local communities and concerned stakeholders’ needs have to be understood well. Based on this understanding, opportunities for improving the strategies for public engagement can be identified. The case studies indicate that it is possible to successfully attain a high level of public participation in offshore wind infrastructure development.



5 OFFSHORE GRID INVESTMENT I: COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

5.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 21.

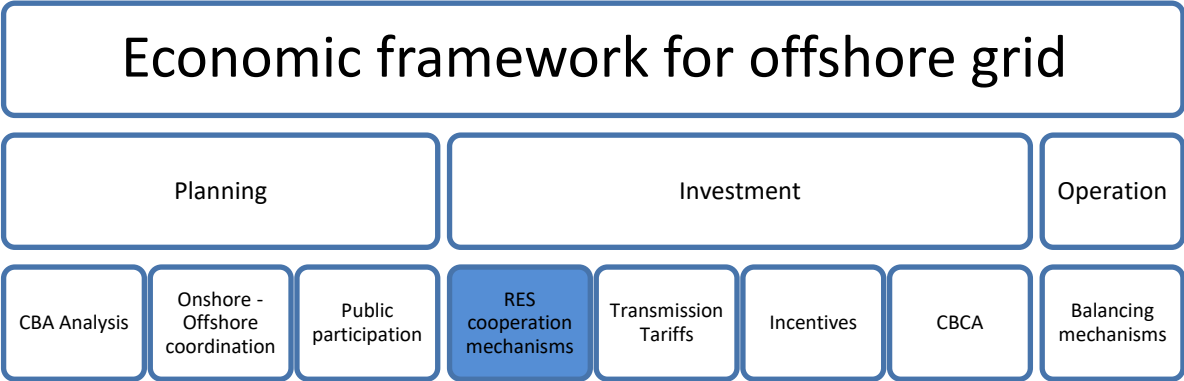


Figure 21: Illustration of the position of this chapter in the overall report structure.

With the aim of increasing the share of renewable energy resources in the European Union’s supply mix and combating climate change, the EU Directive 2009/28/EC on “promoting the use of energy from renewable sources” came into effect on 25 June 2009. The directive set out a target of 20% renewable energy in the EU by 2020 along with 20% reduction in greenhouse gas (GHG) emissions (compared to the 1990 levels) and 20% improvements in energy efficiency. Most importantly, the directive set out legally binding targets for all member states to enable the EU to reach these targets. Each member state was obliged to submit a national renewable energy action plan (NREAP) for reaching these binding targets.

Effective renewable support mechanisms are critical to ensuring a robust development of a decarbonized electrical system in Europe. Member states have implemented diverse types of renewable support mechanisms for incentivizing investment in, and production of electricity from renewable energy sources. Over the years these mechanisms have evolved (and continue to do so) as countries fine-tuned their approaches based on their (and the EU’s) experiences and policy priorities.

Since the beginning of the millennium, renewable support schemes have been a major source of research and debate, in academia as well as practice. Several detailed analyses (qualitative and quantitatively) on this topic regarding the classification of different support scheme approaches, their evolution, their effectiveness and comparison of different approaches have been published over the years. Some examples of the research on this topic are the following: The most recent and updated information on renewable support scheme is available in Council of European Energy Regulators, (2017). Selected resources that provide a greater understanding of

different renewable support schemes are Batlle et al., (2012); Linares et al., (2013); Green and Yatchew, (2012) Canton and Lindén, (2010); Durand and Keay, (2014); Fraunhofer ISI and Ecofys, (2014). A historical review of the renewable support in the EU up to 2011 is published by Haas et al., (2011). Some examples of a comparative analysis of renewable support schemes are Butler and Neuhoff, (2008); Fagiani et al., (2013); Fais et al., (2014); Menanteau et al., (2003); Ringel, (2006).

The EU Directive 2009/28/EC further introduces three types of cooperation mechanisms for implementing renewable support schemes. The aim of encouraging member states to facilitate the implementation of these coordination mechanisms is to provide more effective and cost-efficient exploitation of renewable resources. In some ways this can be considered as the likely next step in the evolution of support for renewables. Consequently, cooperation on renewable support schemes between countries surrounding the North Sea could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. The three cooperation mechanisms that have been introduced are statistical transfers, joint projects, and joint support schemes. Furthermore, the “Clean energy for all Europeans” package proposes that “the Member States shall open support for electricity generated from renewable sources to generators located in the other Member States” (Article 5 of the renewable directive recast) (European Commission, 2016d). Thus, adding to the need for greater understanding of cooperation mechanisms. Selected resources in the literature that provide a greater understanding of these cooperation mechanisms are European Commission, (2013a, 2013b); European Parliament, (2009); Klessmann, (2009); Klessmann et al., (2010); Klinge Jacobsen et al., (2014). Research specifically in the context of offshore wind farms and cooperation mechanisms has been published in Schroeder et al., (2012); Shariat Torbaghan et al., (2015).

Proposed Renewables Directive (recast) (European Commission, 2016d)

Article 5

Opening of support schemes for renewable electricity

1. Member States shall open support for electricity generated from renewable sources to generators located in other Member States under the conditions laid down in this Article.
2. Member States shall ensure that support for at least 10% of the newly-supported capacity in each year between 2021 and 2025 and at least 15% of the newly-supported capacity in each year between 2026 and 2030 is open to installations located in other Member States.
3. Support schemes may be opened to cross-border participation through, inter alia, opened tenders, joint tenders, opened certificate schemes or joint support schemes. The allocation of renewable electricity benefiting from support under opened tenders, joint tenders or opened certificate schemes towards Member States respective contributions shall be subject to a cooperation agreement setting out rules for the cross-border disbursement of funding, following the principle that energy should be counted towards the Member State funding the installation.



4. The Commission shall assess by 2025 the benefits on the cost-effective deployment of renewable electricity in the Union of provisions set out in this Article. On the basis of this assessment, the Commission may propose to increase the percentages set out in paragraph 2.

From the context of the countries surrounding the North Sea, the effectiveness of these support schemes, whether at a national level or as part of a cooperation mechanism, would have a large bearing on investment in and the development of offshore wind farms. This would consequently have a significant impact on the development of transmission infrastructure over the North Sea. Thus, it is important to understand types of renewable support schemes, current implementation status in the countries around the North Sea and possible cooperation mechanisms of renewable support schemes. Therefore, the aim of this internal deliverable is to provide the reader with an understanding of the following aspects of renewable support schemes that are enlisted below.

- Various configuration of renewable support schemes that have been discussed in the literature.
- The status and evolution of national support schemes in the countries of the North Sea.
- The different cooperation mechanisms for renewable support.
- Case studies on attempts at implementing cooperation mechanisms in Europe.

This internal deliverable is subdivided as follows. In Section 5.2, different types of renewable support schemes are discussed. This is followed by a description of the evolution and current implementation status of renewable support schemes in the countries surrounding the North Seas. In Section 5.3, cooperation mechanisms for renewable support are discussed. In Section 5.4, case studies on the implementation of cooperation mechanisms for renewable support are presented. Finally, in Section 5.6, the conclusions are summarised in brief.

5.2 RENEWABLE SUPPORT SCHEMES

A classification of renewable support schemes is presented in

Figure 22. The renewable support schemes can broadly be differentiated into direct methods and indirect methods. Direct methods can be further differentiated into price based or quantity based mechanisms. In a price-based mechanism, the price of renewable electricity (support) is fixed, and the investors choose the quantity (in terms of installed capacity) that they would invest in at the given price. Examples of price-based mechanisms are Feed-in tariffs, Feed-in premiums, etc. In quantity based mechanisms, the capacity required is fixed while the price is determined by market forces (Weitzman, 1974). Renewable certificate market is an example of a price based mechanism. Indirect methods consist of implicit payments and discounts, and institutional support tools (Auer et al., 2009; Linares et al., 2013). In this section, we focus on the direct methods that are predominant in the European Union.

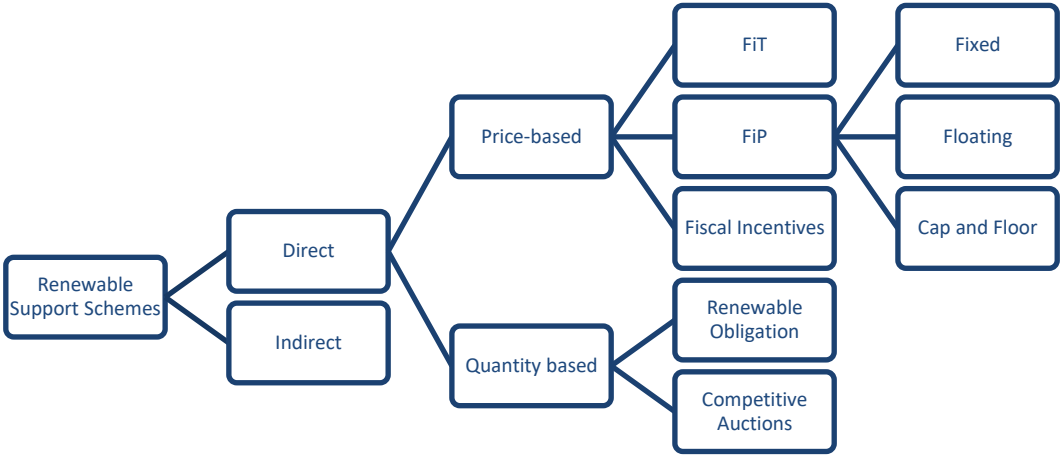


Figure 22: Classification of renewable support schemes.

5.2.1 PRICE BASED RENEWABLE SUPPORT MECHANISMS⁶⁷

5.2.1.1 FEED-IN-TARIFFS

Feed-in-Tariff (FiT) is a renewable support mechanism in which power producers generating renewable electricity are provided a “guaranteed” fixed €/MWh price for each unit of renewable electricity that they generate over a pre-decided length of time. In literature, it is observed that the time duration for which the FiT is provided varies from country to country and ranges between 10 and 30 years (Batlle et al., 2012). The price is a fixed value (which is set either administratively or through an auction) determined such that it provides sufficient revenues for recovery of costs for the given renewable generation technology over the long run. In a FiT scheme, the renewable generator is not affected by market risks as the functioning of the market does not affect its remuneration (Batlle et al., 2012; Del Río et al., 2015). In this, a basic version of FiT has been described. Over the years, different variations have been implemented in practice and have been described in depth in literature. For the understanding of the reader, a stylised version of the FiT is illustrated Figure 23 below.

⁶⁷ This section is based on (Batlle et al., 2012; Couture et al., 2010; Del Río et al., 2015)

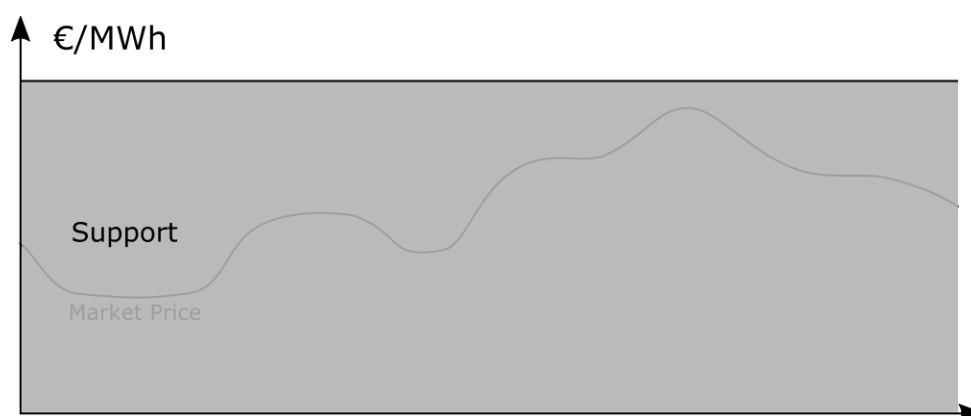


Figure 23: Illustration of a stylised FiT scheme

Advantages of FiT

- Low investment risk due to guaranteed payments.
- Reduces the entry barrier for new market players as there is no need to market electricity.
- No risk from the exercise of market power to inflate revenues.
- The risk from price volatility that arises in quantity based mechanisms are avoided.
- FiT can be targeted to encourage specific types of renewable technologies depending on need.
-

Disadvantages of FiT

- There is a risk of over or under incentive as predicting the correct price is extremely difficult.
- There is no incentive for renewable generators to react to market signals (such as demand and system balancing).
- The level of regulatory risk is high as these contracts are long term.

5.2.1.2 FEED-IN-PREMIUM

In a feed-in premium (FiP) scheme, the renewable power generator receives part of its income from the electricity market, and part of it as a premium (which is set either administratively or through an auction) in addition the revenue from the electricity market (usually in €/MWh). It should be noted that different methods can be utilised to set the reference electricity price used for determining the income of the power generator. Thus, in a FiP scheme, the renewable generator is partly exposed to the risks from the electricity market prices. The level of risk would depend upon the design that is implemented for calculating the premium for the renewable generator. In this report, we will explain three methods for setting the FiP, namely: fixed premium, floating premium, and cap and floor premium. In terms of temporal scope, the FiP is similar to the FiT and can be set for several years into the future.

5.2.1.3 FIXED PREMIUM

In the fixed feed-in premium scheme, the generators are paid a fixed or static remuneration (€/MWh) (which is set either administratively or through an auction) for the power supplied in addition to the variable remuneration that the renewable energy generator receives from the electricity market. Therefore, the total remuneration per unit of electricity generated is the sum of the electricity clearing price and a fixed premium. The calculation of the premium

is made similar to the FiT in terms of long-term cost recovery for the renewable generator. However, renewable generators are exposed to the short-term volatility of the electricity market. For the understanding of the reader, a stylised version of the Fixed FiP is illustrated in Figure 24 below.

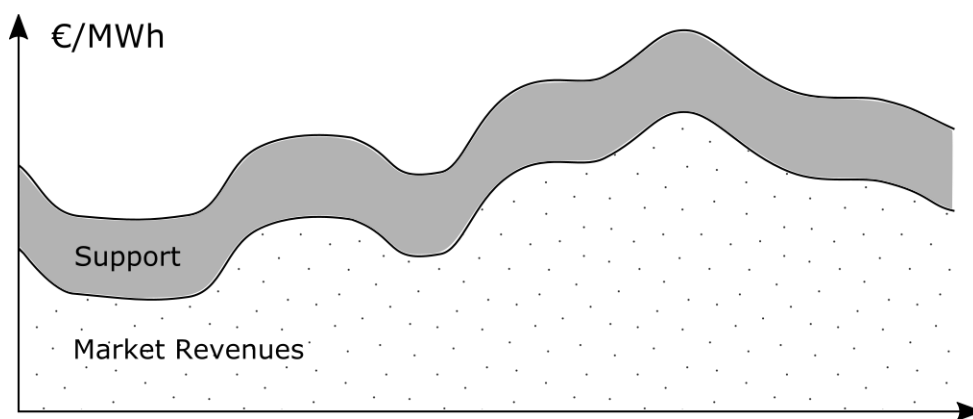


Figure 24: Illustration of a stylised Fixed FiP mechanism

5.2.1.4 FLOATING PREMIUM

The floating feed-in premium mechanism (also in some contexts called a sliding premium) differs from a fixed premium FiP mechanism in terms of its ability to react to electricity market prices. Unlike the fixed premium, the additional remuneration (or premium) (which is set either administratively or through an auction) that is paid to the renewable generators is adjusted depending upon the price that develops in the electricity market to ensure that the renewable generators receive a predefined tariff. In a floating premium mechanism, the variation in the value of the premium to be paid to the renewable energy generator is dependent upon whether a long term (averaged over a time horizon) or a short-term (hourly) perspective is used for determining the reference electricity market price. For the understanding of the reader, a stylised version of the Floating FiP is illustrated in Figure 25 below.

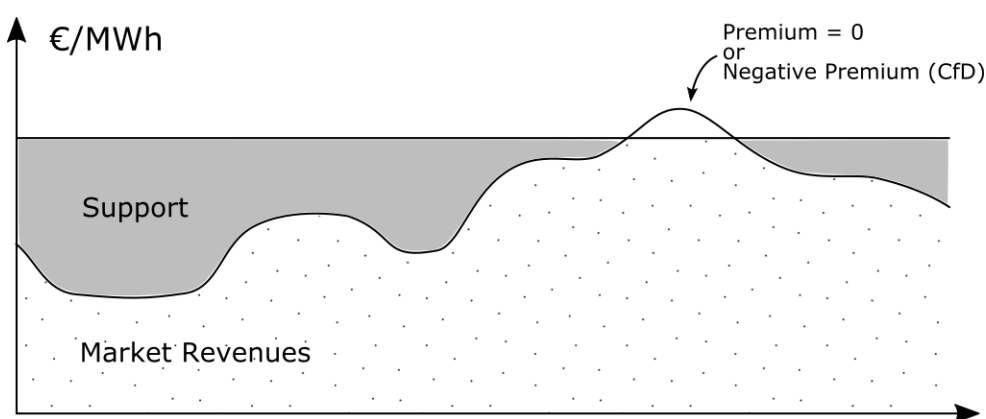


Figure 25: Illustration of a stylised Floating FiP mechanism

5.2.1.5 CAP AND FLOOR PREMIUM

The cap and floor system consist of a (guaranteed) minimum and a maximum payment to the renewable generator. These caps may be based on the total revenue per unit of renewable electricity generated or on the

premium value itself (Couture et al., 2010). Depending upon the system utilised, the value of the premium is adjusted based on the income from the market but within the cap and floor bandwidth. In its simplest form, the administrator sets a “reference premium value”, a floor and a cap value. When the market price is below the floor price, and the difference between the floor and the market price is greater than the reference premium value, the renewable generator is paid an additional revenue that is the difference between the market price and the floor. When the market price is above the floor level or the difference between the floor and the market price is greater than the reference premium level, the renewable generator is paid the support value above. However, the total revenue that the generator receives is capped by the cap value. For the understanding of the reader, a stylised version of the cap and floor FiP is illustrated in Figure 26 below. The Spanish example of the cap and floor system is discussed in detail by Schallenberg-Rodriguez and Haas, (2012).

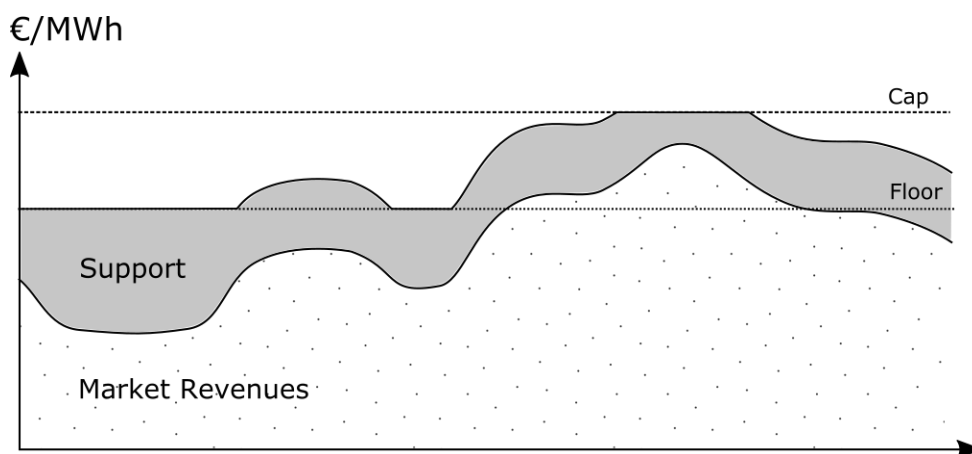


Figure 26: Illustration of a stylised Cap and Floor FiP mechanism

Advantages of Feed-in premium

- Renewable generators are more responsive to electricity market signals and better economic efficiency.
- The risk from price volatility that arises in quantity based mechanisms is avoided.
- The FiP can be targeted to encourage specific types of renewable technologies depending on need.
-

Disadvantages of Feed-in premium

- It is difficult to determine the right premium level (or price, and floors).
- Greater investor risk as there is no purchase guarantee.
- The risk of market price fluctuation is greater compared to a FiT.

5.2.1.6 FISCAL INCENTIVES

Fiscal incentives can be broadly divided into three categories, namely: tax incentives, investment incentives, and financing incentives. Tax incentives may be in the form of accelerated depreciation for renewable technology assets, tax exemptions, and tax credits. Investment incentives may consist of capital subsidies for developers of renewable projects (Schmalensee, 2012, 2009). Financing incentives can be in the form of ‘soft loans’ or loans

that are provided at a low-interest rate with long repayment periods to make renewable projects more attractive and viable for investors.

Advantages of Fiscal Incentives

- Reduction in the cost of financing renewable projects.
- There is no direct impact on electricity consumers in the form of an increase in tariffs.
-

Disadvantages of Fiscal Incentives

- Focused on installed capacity rather than production.
- Tax incentives may apply only to domestic consumers and discourage international investments
- High regulatory risk as these incentives are subject to adjustment
- Cross-subsidization between taxpayers and electricity consumers

5.2.2 QUANTITY-BASED RENEWABLE SUPPORT MECHANISMS

5.2.2.1 RENEWABLE OBLIGATIONS

In this mechanism (which is also known as a quota system in some contexts), the regulator sets the quantity of renewable electricity that the consumers and generators are obliged to ensure in their consumption and generation portfolio respectively. Stakeholders that do not comply with this obligation would be subject to some type of non-compliance penalty that would vary depending upon the regulatory design that is adopted by the country.

In its basic form, all renewable generators are provided certificates for each unit of electricity that they produce. These certificates are traded between stakeholders with excess certificates and those who need these certificates to ensure compliance with the regulatory obligation. Depending on the regulatory requirements of the implementing country, different variations can be implemented. An example is to link the number of certificates issued per unit of electricity generated based on renewable technology. This way one technology can be preferred over another. In the UK this has been called as a “banding mechanism” (DBEIS and Ofgem, 2013; Kitzing et al., 2012). Another method is to set specific prices for specific technologies as has been done in Belgium for offshore wind (described later in this report). For the understanding of the reader, a stylised version of the Renewable Obligations (RO) is illustrated in Figure 27 below.

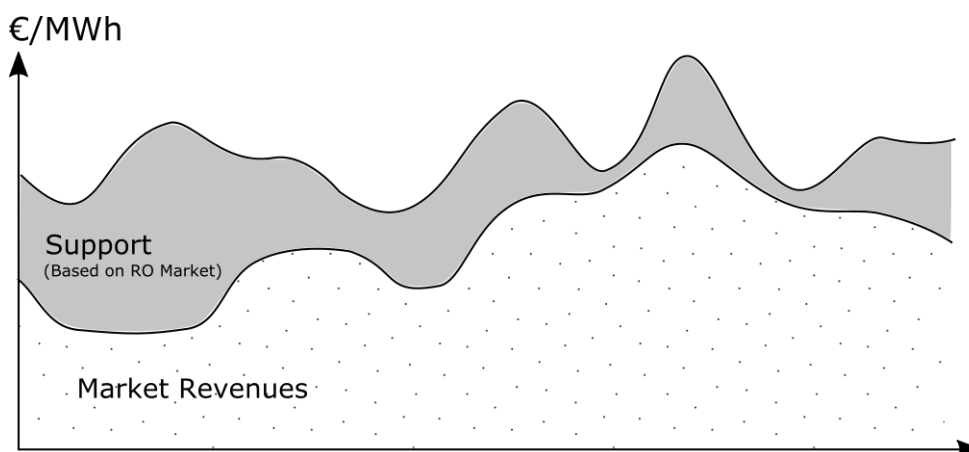


Figure 27: Illustration of a stylised Renewable Obligations mechanism

Advantages of Renewable Obligations

- Under ideal conditions, these should provide the most economically efficient outcome to reach policy goals.
-

Disadvantages of Renewable Obligations

- The exposure to electricity market price and certificate market price risk.
- There is a risk of the exercise of market power if the certificate market is not liquid.
- Significant transaction costs associated with the certification mechanism.

5.2.2.2 COMPETITIVE AUCTIONS

Auctions are being used widely in Europe for determining support levels for offshore wind farms. In literature, auctions are classified as quantity based mechanisms (Batlle et al., 2012). However, Fraunhofer ISI and Ecofys, (2014) contend that auctions should be considered as a method for the cost-effective allocation of financial support for renewables. Therefore, auctions can be used in combination with different support schemes (e.g. setting the strike price for feed-in premium).

In the context of renewable energy, the regulatory authority determines the quantity of renewable capacity that is required to be constructed and therefore to be auctioned. These auctions can also be technology specific where the quantity for various renewable technologies is defined. A bidding process is carried out to determine the most economical offer from the developers. The winner of the bids is offered long-term contracts for electricity generation. The incentive for the renewable generation may be fixed on a “pay as bid” basis, where the incentive is equal to the bidding price for the project or using a “uniform pricing” method (Batlle et al., 2012).

Advantages of competitive auctions

- The regulator does not need to identify the efficient support level, as it is set by the participants.
- Lower risk due to long-term contracts.

Disadvantages of competitive auctions

- There is a risk that developers may fail to deliver due to low clearing prices caused by underestimation of development cost (in the case of immature technologies) or intense competition

5.2.3 NATIONAL RENEWABLE SUPPORT SCHEMES AROUND THE NORTH SEA

A detailed description of support schemes in the different support schemes that have been implemented by countries around the North Sea has been presented in the deliverables of WP7.1. In this section, we provide an overview of the renewable support mechanisms that are currently being used and the evolution of these support schemes in the context of harmonisation. A broad classification of the different countries based on the type of mechanism implemented is presented in Table 12.

Table 12: Broad Classification of renewable support schemes in different North Sea Countries

Feed-in Premium	Feed-in Tariffs	Renewable Obligation
Denmark Germany UK The Netherlands	France	Belgium ⁶⁸ Norway Sweden

In Denmark, a system resembling a feed-in premium scheme is used to support offshore wind generation. Developers that win tenders for building wind farms are paid an additional remuneration over the market price that they receive for selling their electricity. The value of the remuneration is the difference between the strike price and the electricity market price. In case the market price crosses the strike price, a negative subsidy would apply (Folketinget, 2008). The new German scheme that came into force in 2014 too is a Feed-in premium scheme (BMW, 2014). Before 2014 a feed-in tariff system was utilised.

The UK has implemented a floating feed-in premium scheme (also called “contract for differences” CfDs). In this system, if the market price is lower than the ‘strike price’, the renewable generator is provided with additional remuneration, which is the difference between the strike price and the market price (UK Parliament, 2013). The UK has recently phased out its old renewable obligations scheme from 31st March 2017 (OFGEM, 2017) which was running parallel with the CfD for some period.

France utilises a feed-in tariff mechanism where the developer winning the tender for constructing offshore wind farms is provided with a purchase guarantee at the strike price (Monaco and Prouzet, n.d.). Interestingly, wind farms that are built in territorial seas or internal waters are required to pay an additional tax which is provided to the municipalities near these wind farms. The idea is to encourage offshore wind farms to be built outside the territorial waters of France (CRE, 2016; Parlement français, 2012). It should be noted that for some renewable technologies, France has shifted to a feed-in premium system. This shift may be a precursor towards a complete switch from Feed-in tariffs to Feed-in Premiums (International Energy Agency, 2016a).

⁶⁸ As explained later in the section it could be said that in Belgium, offshore wind has been provided with a technology specific hybrid floating feed-in premium renewable support scheme.

The Netherlands utilises a floating feed-in premium mechanism for renewable support called SDE+ (Stimulerend Duurzame Energie+). The remuneration is determined using a tendering process. For all onshore renewable projects, the tendering is technology neutral. However, the duration of the remuneration is dependent upon technology type. The tendering for offshore wind farms are held separately for a 15-year remuneration period (International Energy Agency, 2017; RVO, 2017).

In Norway (See: Eletsertifikatloven – Norwegian Electricity Certificate Act) and Sweden (See: Swedish Electricity Certificate Act Lag (2003:113) om elcertifcat) utilise a tradable green certificates scheme (renewable obligation) which is shared between the two countries. This is an example of a joint support scheme mechanism and will be discussed later in this report. As a technology-neutral mechanism, this has been criticised as not an efficient mechanism to promote offshore wind investments, considering that costs are 40-50% higher than onshore investments (Jacobsson et al., 2013). Also, the TGC mechanism increases uncertainties for the investor, as revenues coming from the support are volatile, changing in function of the quota levels.

In the context of the offshore wind farm, Belgium provides a very interesting case of renewable support based on technology. Belgium has a renewable obligation (renewable certificate) scheme implemented (Council of European Energy Regulators, 2017). However, renewable certificates assigned to production from offshore wind have been provided with additional price certainty.

The offshore wind that reached financial closure before May 1st 2014, a fixed price per certificate is administratively set (€ 107 per 1 MWh before May 1st 2014 for first 216 MW capacity and € 90 per 1 MWh for the capacity above 216 MW). This system appears to be a hybrid fixed feed-in premium where the prices for the renewable certificate are fixed. Thus, the generator knows the exact €/MWh support that will be provided. The certificate price for projects with financial closure after May 1st 2014, the minimum price is calculated as the difference between the levelised cost of electricity (LCOE) and the electricity reference price, which is adjusted by a correction factor (International Energy Agency, 2016b). This system appears to be a hybrid floating feed-in premium mechanism. Thus, it could be said that in Belgium offshore wind has been provided with a technology-specific hybrid floating feed-in premium renewable support scheme. Thus, it could be said that considering support for offshore wind, five out of the eight countries have a feed-in premium renewable support mechanism.

5.2.4 EVOLUTION OF RENEWABLE SUPPORT SCHEMES AROUND THE NORTH SEA

Figure 28 is presented to provide the reader with a pictorial depiction of the current situation with regard to the implementation of national renewable support schemes in the countries of the North Sea. As described in 5.2.3, different countries have implemented their variations of the aforementioned three mechanisms. The United Kingdom has evolved from a renewable obligations mechanism which was completely phased out to a contract for differences which is the feed-in premium system. On the other hand, Germany moved from a Feed-in tariff to a Feed-in Premium system. As discussed earlier, Belgium provides a very interesting case of a hybrid between a feed-in premium and renewable obligations in the context of offshore wind farms. Furthermore, the French too have shifted from a FiT to a FiP for some renewable technologies.



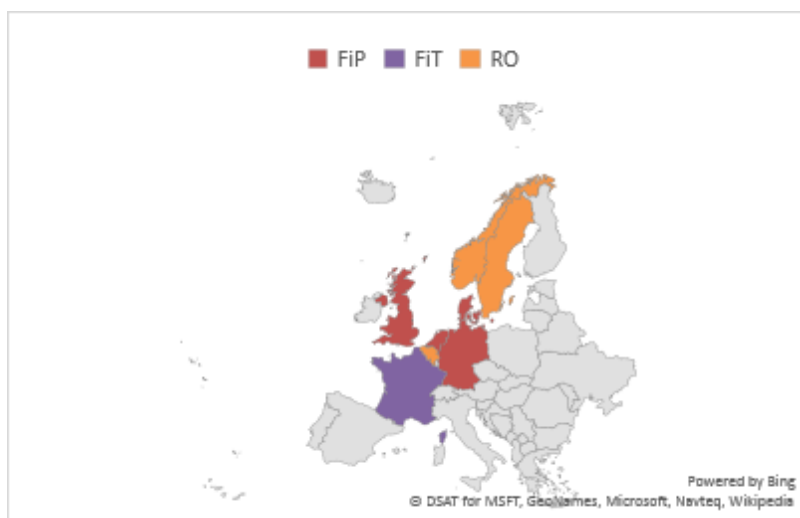


Figure 28: Broad Classification of renewable support mechanisms in countries under consideration.

It can be observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration in this report have explicitly implemented a feed-in premium scheme. Furthermore, it is observed that a floating (sliding) feed-in premium is a preferred type of feed-in premium for implementation in these nations.

The shift from feed-in tariffs towards market-driven renewable support mechanisms is in line with the recommendations of the European Commission. In their guidance for the design of renewables support schemes (European Commission, 2013c), the European Commission indicated a preference for greater “market exposure” of renewable generators and contended that a competitive electricity market should enable effective and cost-efficient energy production and investment decisions.

On the whole, a shift towards feed-in premium renewable support schemes is observed in the countries around the North Sea. This move towards a similar type of renewable support scheme can be considered a welcome step towards harmonisation and cooperation between these countries in administering renewable support schemes. However, notwithstanding this shift, it should be noted that Norway and Sweden continue to have a joint renewable obligations mechanism. Thus, we can consider the feed-in premium and renewable obligation as the two predominant renewable support mechanisms that have been implemented in the countries that are under consideration in this report.

5.2.5 KEY TAKEAWAYS FOR MESHED OFFSHORE WIND DEVELOPMENT FROM EVOLUTION OF RENEWABLE SUPPORT SCHEMES

- The recent German wind tenders which had a minimum price of 0.00 €/KWh (BMW, 2017) bear witness to the viability of offshore wind generation in providing clean electricity competitively.

- A shift from feed-in tariffs towards market-driven renewable support mechanisms is in line with the recommendations of the European Commission.
- The feed-in premium appears to be the most commonly used instrument for providing renewable support in the countries surrounding the North Sea.
- The method of administration of the feed-in premium may vary from country to country
- Technology-specific competitive auctions are the preferred mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.
- The technology specificity of these auctions allows the regulatory authorities to control the quantity of installed capacity of the wind offshore.
- Technology neutral renewable obligations appear to have a limited positive impact on the development of offshore wind farms.

5.3 COOPERATION MECHANISMS FOR RENEWABLE SUPPORT

A key issue with regards to (nationalised) renewable support schemes and offshore wind development today is that to benefit from this support, the renewable electricity generated by generators needs to feed this electricity only into the funding state (more details: Shariat Torbaghan et al., 2015).

From the context of meshed offshore wind development, such a framework does not facilitate investment in offshore wind farms that are connected to two or more nations or are spread over the territory of multiple countries. Moreover, in a meshed scenario, the direction flow of electricity from these offshore wind farms is uncertain. In other words, it is observed that the current national mechanisms may be incompatible for developing projects that are outside the borders of implementing nations or that are present in a meshed network, thus presenting a critical roadblock to the development of a meshed offshore wind system. This obstacle could be resolved with the introduction of 'cooperation mechanisms.'⁶⁹ However, it should be noted that cooperation mechanisms have rarely been utilised by the member states of the European Union.

The European Commission first introduced cooperation mechanisms as part of the Directive 2009/28/EC on the promotion of the use of energy from renewable sources. These cooperation mechanisms were introduced with the aim of 1) enabling and encouraging member states to exploit the renewable resources in Europe in the most effective and cost-efficient manner. 2) To enable greater cross-border cooperation between member states on renewable energy policies. The three cooperation mechanisms that were suggested by the European Commission are Statistical Transfers, Joint Projects and Joint Support Schemes (European Commission, 2013b, 2013a).

Directive 2009/28/EC

This Directive aims at facilitating cross-border support of energy from renewable sources without affecting national support schemes. Optional cooperation mechanisms between Member States which allow them to agree on the extent to which one Member State supports the energy production in another and on the extent

⁶⁹ For more info please visit: <http://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive/cooperation-mechanisms>.

to which the energy production from renewable sources should count towards the national overall target of one or the other. In order to ensure the effectiveness of both measures of target compliance, i.e. national support schemes and cooperation mechanisms, it is essential that Member States are able to determine if and to what extent their national support schemes apply to energy from renewable sources produced in other Member States and to agree on this by applying the cooperation mechanisms provided for in this Directive.

Along the same lines as the stated goals of the European Union, the literature suggests that implementation of cooperation mechanisms would enable 1) a step closer to regional integration, with an increase in cross-border cooperation between member states and 2) greater economic efficiency as has been discussed in several studies.

The results from the Green-X model developed by the Technical University of Vienna that were presented in European Commission, (2013c) estimated that greater cooperation would lead to a 5% reduction in the cost of generation, a 6% reduction in support costs, and 3% lower capital costs. Similarly, results from another report (European Commission, 2012) quoted in European Commission (2013c) indicate that when compared to cooperation mechanisms, the use of separate national renewable support schemes would lead to an additional cost of nearly € 2bn annually for achieving their 2020 renewable targets. The aforementioned benefits arising from the implementation of cooperation mechanisms makes them an attractive alternative for the countries around the North Sea to further stimulate growth in the offshore wind power sector. Furthermore, experiments on the utilisation of such cooperation mechanisms are already being conducted in European countries in order to collaborate in supporting cross-border investments in renewable technologies.⁷⁰

Nevertheless, it should be noted that the EC's evaluation of the EU's Renewable Energy Directive in November 2016 (European Commission, 2016e) found that member states had seldom utilised cooperation mechanisms for the renewable support that was introduced in the Renewable Energy Directive 2009. The only significant example was the Sweden-Norway joint certificate scheme.

Directive 2009/28/EC

Whilst having due regard to the provisions of this Directive, Member States should be encouraged to pursue all appropriate forms of cooperation in relation to the objectives set out in this Directive. Such cooperation can take place at all levels, bilaterally or multilaterally. Apart from the mechanisms with effect on target calculation and target compliance, which are exclusively provided for in this Directive, namely statistical transfers between Member States, joint projects and joint support schemes, cooperation can also take the form of, for example, exchanges of information and best practices, as provided for, in particular, in the transparency platform established by this Directive, and other voluntary coordination between all types of support schemes.

In this section, we discuss the three aforementioned cross-border cooperation mechanisms for the renewable support that have been introduced in the Renewable Energy Directive 2009/28/EC.

⁷⁰ In July 2016 the Danish and the German governments signed a cooperation agreement on the mutual opening of auctions for PV installations. See for example: <http://www.bmwi.de/EN/Service/search,did=774486.html>

5.3.1 STATISTICAL TRANSFERS

A statistical transfer mechanism enables countries in which the electricity produced from renewables in excess of the minimum compliance level to bilaterally trade this excess production “credit” with countries that are unable to reach their targets for various reasons. A statistical transfer agreement can either be short term for one year or as part of a long-term strategy of a country. In this mechanism, no physical exchange of electricity occurs, but rather the attribution of renewable production towards a particular country is altered (European Commission, 2013a, 2009a). The key aspects that the countries involved need to agree upon are 1) appointment of a “contact point” at the national level for coordinating the mechanism. 2) Procedures for dispute settlement, sharing of the renewable credits in terms of quantity and time, etc. (European Commission, 2013a). A detailed description along with guidance for implementation of statistical transfers has been published by the European Commission in (European Commission, 2013a).

A statistical transfer mechanism can be explained with the example of a two countries system. Consider Country A, in which successful implementation of renewable policies has led to a substantial investment in renewable generation technologies, thereby enabling it to exceed its binding renewable production targets. Country B, on the other hand, is unable to achieve its binding renewable production targets. However, the total of the production in Country A and B together is sufficient to achieve the targets of both countries combined. In a statistical transfer mechanism, country A may monetize its extra renewable production by selling it bilaterally to Country B. During the accounting of renewable production, these transferred credits will now be added to the portfolio of country B and deducted from that of Country A.

European Directive 2009/28/EC: Article 6 - Statistical transfers between Member States

1. Member States may agree on and may make arrangements for the statistical transfer of a specified amount of energy from renewable sources from one Member State to another Member State. The transferred quantity shall be:
 - a. deducted from the amount of energy from renewable sources that is taken into account in measuring compliance by the Member State making the transfer with the requirements of Article 3(1) and (2); and
 - b. added to the amount of energy from renewable sources that is taken into account in measuring compliance by another Member State accepting the transfer with the requirements of Article 3(1) and (2).

A statistical transfer shall not affect the achievement of the national target of the Member State making the transfer.

2. The arrangements referred to in paragraph 1 may have a duration of one or more years. They shall be notified to the Commission no later than three months after the end of each year in which they have effect. The information sent to the Commission shall include the quantity and price of the energy involved.
3. Transfers shall become effective only after all Member States involved in the transfer have notified the transfer to the Commission.

The advantages and disadvantages of statistical transfers have been described in detail by Klessmann, (2009); Klessmann et al., (2010). The main advantages of this method (over the other two alternatives) that have been listed are 1) It is a straightforward mechanism to implement and administer. 2) It has no negative impact on the national support scheme's performance 3) No technology restrictions of any kind are necessary. Thus, statistical transfers provide an incentive for countries with enormous potential for installing renewable power plants cost effectively to push investment in renewable generation aggressively and exceed their required targets.

On the other hand, the main disadvantages listed are: 1) the dependence on the ability of member states to develop excess renewable resources to trade. Due to this ex-post nature of the scheme, there is a risk that member states which depend on statistical transfers for reaching their targets may not find enough sellers if the market is illiquid. 2) There is no additional incentive for investment in new projects (and improvement in efficiency) as the development of renewable continues to depend upon nature and level of renewable support in a particular country, and there is no incentive for developers to invest in the region with the cheapest potential notwithstanding the support scheme in that region.

Furthermore, the European Commission encourages member states to “aim for a long-term ex-ante agreement, providing a consistent and predictable framework for both parties” (European Commission, 2013a). However in an imperfect market, committing renewable credits to another country in advance entails a high level of risk for the country that is selling it (Schroeder et al., 2012). As such in the literature (Klessmann et al., 2010; Schroeder et al., 2012) it is contended that statistical transfer appears to be a viable alternative for adjusting positions between countries close to the deadline.

The robust development of the offshore wind potential in the North Sea can be considered as one of the goals of any cooperation mechanisms on the renewable support that the countries of the North Seas may consider for implementation. Based on the current research on this topic, it appears that a statistical transfer does not aid in reaching this goal as it does not provide any additional incentive for investment in the new project. Furthermore, the investment incentive continues to be based on national renewable policies in this scenario.

5.3.2 JOINT PROJECTS

Two or more countries may cooperate with each other for the joint development of renewable energy projects. These countries could either be the EU Member States or third countries (European Commission, 2013a; Shariat Torbaghan et al., 2015). In the process of development of these joint process, they may also need to negotiate an agreement on the allocation of renewable energy production credit for the electricity generated by the participating countries (Schroeder et al., 2012). Furthermore, similarly to the statistical transfer, the energy produced by a joint project does not need to physically flow into the system of the participating countries (European Commission, 2009a). A detailed description along with guidance for implementation of joint projects has been published by the European Commission in (European Commission, 2013a). The joint auction scheme for PV launched between Germany and Denmark can be considered as an example of cooperation under a joint projects mechanism.



European Directive 2009/28/EC: Article 7 - Joint projects between Member States

1. Two or more Member States may cooperate on all types of joint projects relating to the production of electricity, heating or cooling from renewable energy sources. That cooperation may involve private operators.
2. Member States shall notify the Commission of the proportion or amount of electricity, heating or cooling from renewable energy sources produced by any joint project in their territory, that became operational after 25 June 2009, or by the increased capacity of an installation that was refurbished after that date, which is to be regarded as counting towards the national overall target of another Member State for the purposes of measuring compliance with the requirements of this Directive.
3. The notification referred to in paragraph 2 shall:
 - a. describe the proposed installation or identify the refurbished installation;
 - b. specify the proportion or amount of electricity or heating or cooling produced from the installation which is to be regarded as counting towards the national overall target of another Member State;
 - c. identify the Member State in whose favour the notification is being made; and
 - d. specify the period, in whole calendar years, during which the electricity or heating or cooling produced by the installation from renewable energy sources is to be regarded as counting towards the national overall target of the other Member State.
4. The period specified under paragraph 3(d) shall not extend beyond 2020. The duration of a joint project may extend beyond 2020.
5. A notification made under this Article shall not be varied or withdrawn without the joint agreement of the Member State making the notification and the Member State identified in accordance with paragraph 3(c).

The main drivers that have been identified for countries to participate in joint projects are 1) Cost-efficiency: It allows countries to pursue cheaper alternatives outside their borders for reaching their renewable production and reduce the cost of support (European Commission, 2009a; Schroeder et al., 2012). 2) Technology development and innovation: joint projects would assist in better-enabling economies of scale in immature technologies due to the sharing of costs, thus becoming a driving force for innovation. 3) Benefits to domestic industry and local markets: Infusion of capital into such projects would have a positive impact on not only the development of the renewable sector but also the economy as a whole. An example would be the additional job creation due to these projects in the host country. 4) Security of supply: Both countries may benefit from improvement in security of supply due to the joint projects, in terms of additional generation. 5) Long-term cooperation: such projects may become a launching pad to greater cooperation between member states for achieving various policy goals. (European Commission, 2013a). However, due to overlaps between such arrangements and the national support mechanisms, there is a risk that such projects may reduce the effectiveness of the national support schemes. The advantages and disadvantages of joint projects have also been described in detail by Klessmann, (2009; Klessmann et al., (2010).

The countries participating in joint projects need not implement a separate joint renewable support scheme. In this context, the main benefit of using the existing mechanisms would be regarding minimising legislative and



regulatory modifications. On the other hand, as part of the joint project mechanism, the countries involved may also agree upon a project-specific joint support scheme (also called a “cooperation specific support mechanism”). According to the European Commission, (2013b), member states appear to favour “cooperation specific support mechanisms.” This type of combination could be extremely relevant from the meshed offshore wind development perspective, where electricity may flow into different countries from the same installation.

5.3.3 JOINT SUPPORT SCHEMES

As the name suggests in a joint support scheme alternative for cooperation, the national renewable support schemes (FiP, FiT or RO) of the participating countries are harmonised into a single type of support scheme or replaced by a single unified renewable energy support scheme. Under such a scheme, a large region with exploitable renewable energy resources spanning over two or more countries will be governed by a single renewable support mechanism. A detailed description along with guidance for implementation of joint support schemes has been published by the European Commission in (European Commission, 2013a).

The main argument in favour of applying a joint support scheme is that the implementation of a single support scheme across a wider region is expected to lead to an improvement in the overall efficiency of the support mechanism. As the same incentive would be provided over the entire region consisting of the participating countries, the most economically viable sites would eventually be developed. Such a development should lead to lower cost of renewable support as compared to a system with multiple national support mechanisms that are not harmonised (European Commission, 2013a). It is also observed that the current national support schemes are incompatible for developing projects that are outside the territory of the governing country. In the coming years, the development of such projects would be critical for maximising the exploitation of renewable energy resources (Shariat Torbaghan et al., 2015). In such a scenario, joint support schemes appear to be an effective alternative.

However, it should be noted that although cost optimisation regarding saving from renewable support is crucial, a holistic perspective must be taken while selecting and implementing any joint support scheme. For example, the development of a cheap renewable technology in one part may reduce the cost of support but may lead to a significant increase in costs related to the transmitting of this electricity to the load centres. Furthermore, development of the most cost-effective locations for renewable exploitation over the entire region may lead to a skewed distribution of the installed capacity over the territories of the involved countries. Therefore, there is a risk that the individual national goals may not be met.

European Directive 2009/28/EC leaves the design of the joint support scheme up to the member states. Depending on their existing schemes, future policy goals, technological constraints, etc. the countries may choose a design that sufficiently addresses the requirements of all the countries involved. The member states may follow guiding principles for implementing and reforming renewable support schemes that have been set out in the European Commission, (2013c). In the context of accounting of the renewable generations towards the national renewable targets, two options are suggested. 1) statistical transfer between the participating nations 2) using a pre-defined distribution rule which is negotiated by the participating nations.



An example of the joint support schemes in Europe is the joint renewable certificate scheme that has been implemented in Norway and Sweden since 2012. This is the also the first example of implementation of such a joint mechanism.



European Directive 2009/28/EC: Article 11 - Joint support schemes

1. Without prejudice to the obligations of Member States under Article 3, two or more Member States may decide, on a voluntary basis, to join or partly coordinate their national support schemes. In such cases, a certain amount of energy from renewable sources produced in the territory of one participating Member State may count towards the national overall target of another participating Member State if the Member States concerned:
 - a. make a statistical transfer of specified amounts of energy from renewable sources from one Member State to another Member State in accordance with Article 6; or
 - b. set up a distribution rule agreed by participating Member States that allocates amounts of energy from renewable sources between the participating Member States. Such a rule shall be notified to the Commission no later than three months after the end of the first year in which it takes effect.
2. Within three months of the end of each year each Member State having made a notification under paragraph 1(b) shall issue a letter of notification stating the total amount of electricity or heating or cooling from renewable energy sources produced during the year which is to be the subject of the distribution rule.
3. For the purposes of measuring compliance with the requirements of this Directive concerning national overall targets, the amount of electricity or heating or cooling from renewable energy sources notified in accordance with paragraph 2 shall be reallocated between the concerned Member States in accordance with the notified distribution rule.

In the Countries surrounding the North Sea, two types of renewable support schemes appear to be preferred: 1) feed-in premium (more specifically floating feed-in premium) which have by now been implemented by the majority of these countries and 2) renewable obligations which have already been implemented jointly by Sweden and Norway.

While considering the possible implementation of a joint support scheme amongst the countries surrounding the North Sea, the central element of the discussion would be the design and type of mechanism that is implemented to ensure an equitable distribution of costs and benefits that arise from renewables. Considering the evolution mentioned above of renewable support mechanisms, the two renewable support mechanisms that have been predominantly used in these regions, namely: (floating) feed-in premium and renewable obligations may be interesting alternatives for consideration.

In the case of feed-in premiums, we already see a certain degree of harmonisation as the majority of the countries have already implemented these mechanisms and are experienced at implementing, and administering this type of support schemes. Thus, this may provide greater ease of implementation. On the other hand, a renewable obligation scheme has already been implemented jointly between Sweden and Norway, thus providing the benefit of previous experience to expand this region. Therefore, these two schemes (especially the feed-in premium) can be a starting point for developing a possible effective and efficient solution for implementing a joint support scheme in this region.



5.3.4 OFFSHORE SPECIFIC JOINT SUPPORT SCHEMES

In the context of meshed offshore wind development, the implementation of a technology-specific joint support scheme appears as an attractive and a relevant alternative for further discussion. Such hybrid mechanisms would consist of elements from joint projects and joint support schemes.

A meshed offshore wind grid would have some unique dimensions which make it different from an onshore system. Onshore generation assets that are built within the territory of the country inject their power into the national grid. On the other hand, the direction of the electricity flow of an offshore wind farm that is connected to a meshed grid is uncertain, notwithstanding in which country's territorial waters the OWF is built or where the commercial transactions are conducted. In such a scenario, unharmonized renewable support regimes in the countries interconnected by this meshed grid would lead to the risk of regulatory failure. The efficiency and effectiveness of national support schemes could be compromised as the country providing the support may not receive the benefit from this renewable generation.

The implementation of a technology-specific joint support scheme would enable greater harmonisation in the support that the offshore wind farms would receive. However, it is vital that while designing the support scheme, all participating countries calculate and agree upon the costs that they would bear and benefits that they would receive from the implementation of such a scheme from an early stage. Klessmann et al., (2010) have identified five feasible principles to account for the costs and benefits. Such a scheme would also lead to the exploitation of the most cost-effective offshore sites. Moreover, the implementation of this support scheme would aid in achieving a more balanced allocation of the costs and benefits between the countries. However, further research on the methods of calculating, and allocating these costs and benefits needs to be conducted.

By making the support scheme offshore (technology) specific, the national support schemes can be retained for another type of renewable generation without hampering their effectiveness and minimising the adverse cross-policy effects. Although such a mechanism would encourage the development of offshore wind in a meshed system, depending upon the preference of the countries towards technology, care should be taken that discrimination between support for different technologies is minimised (Klessmann et al., 2010).

Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a "technology-specific joint support scheme".

5.3.5 KEY TAKEAWAYS ON COOPERATION MECHANISMS FOR MESHED OFFSHORE WIND DEVELOPMENT

- Unharmonized national support mechanisms may not be able to provide an efficient incentive in a meshed offshore system where the direction of flow of electricity is uncertain.
- Cooperation mechanisms for renewable support may be a solution.



- The European Commission has proposed three cooperation mechanisms: Statistical Transfers, Joint Projects and Joint Support Schemes.
- Technology-specific joint support scheme that combines the elements of joint projects and joint support scheme seems to be a relevant alternative from the perspective of offshore wind development.
- Considering the evolution of the support schemes in the countries around the North Sea, a technology-specific feed-in tariff administered through a competitive auction appears to be a good starting point for developing a “project specific joint support scheme.”

5.4 CASE STUDIES

5.4.1 CASE STUDY A: GERMANY-DENMARK JOINT PV AUCTION

5.4.1.1 INTRODUCTION

In July 2016, Germany and Denmark signed a cooperation agreement on mutual auctions for ground-mounted PV installations (BMW, 2016). The mutual auctions were intended to strengthen regional cooperation between Denmark and Germany and help both countries meet their renewable energy generation targets. Both Germany and Denmark had prior experience of renewable energy auctions (AURES, 2015) but Germany took a strong role in organising this cross-border auction and successfully applied to the EU Commission for its approval. Germany had demonstrated that technology-specific auctions would ensure a more cost-efficient outcome compared to a technology-neutral bidding. Additionally, Germany had shown that technology-specific auctions could be used as targeted actions to address grid instability and integration issues (European Commission, 2016f). Consequently, the cross-border pilot auctions were designed using just one renewable energy technology, solar PV.

5.4.1.2 OVERVIEW OF THE AUCTION MECHANISM

The cooperation mechanism pilot consisted of two elements. In November 2016 Denmark partially opened an auction round of 20 megawatts (MW) capacity for ground-mounted solar PV projects from Germany. In exchange, Germany opened an auction for 50 MW in Denmark (Clean Energy Wire, 2016).

In contrast to the national auctions, the “pay-as-bid” system, in which every successful bidder is awarded a contract based on the price specified in their bid, a “uniform pricing procedure” is utilised for the cross-border auctions. In this system, the last successful bid to be accepted sets the price for all successful bids. The Danish-German auction is being treated as supplementary to existing national solar PV auctions taking place in Germany so that bidders can submit bids to both auctions (Meza, 2016).

5.4.1.3 RATIONALE

The collaboration aimed to (i) strengthen regional cooperation, (ii) further understanding of the challenges in integrating renewables, (iii) further develop friendly relations, (iv) trial a framework for the partial opening of the national support schemes, and (v) facilitate cross-border exchanges (More Details in cooperation agreement: (Kingdom of Denmark & Federal Republic of Germany, 2016)).

5.4.1.4 DESIGN OF THE AUCTION MODEL

The international cooperation of the Danish-German auctions is intended to be mutually beneficial and have a genuine impact on the energy transition of both countries. It is an effort to increase the amount of renewable energy produced by both countries and to do so in the most efficient way possible (Kingdom of Denmark & Federal Republic of Germany, 2016).

The Danish-German auction model is only one of several innovative auction models being trialed by the German government to lower renewable energy costs. Germany is committed to testing designs that would incorporate grid integration costs or tender for a specific electricity quality (European Commission, 2016f). From January 2017, national auctions have been organised for selected offshore wind installations, onshore wind installations above 750kW, solar installations above 750 kW and biomass and biogas installations above 150 kW. It is understood that the auction in Denmark was its first for solar PV, having focused previous competitive auctions on offshore wind.

EU Renewable Energy Policy

EU policy influenced the decision to implement this cross-border auction model. The EC recommends that the European Member States begin to implement more market-based solutions to support renewable energy, and auctions are market-based and competitive. Additionally, comparatively new EU state-aid rules encourage member states to open up 5% of the renewable energy capacity they intend to install each year to other EU countries via project tenders, conditional upon the agreement that is reached between the participating countries or under the principle of “reciprocity” (Radowitz, 2016b).

German National Renewable Energy Auctions

The Danish-German auctions were intended to be complementary to existing German and Danish auctions. In the case of Germany, bidders can submit bids for both national and international auctions. It remains unclear whether or not the trial international solar PV auctions will be extended.

5.4.1.5 PERFORMANCE

In November 2016, the 50MW German auction for ground-mounted solar took place. It resulted in the lowest solar PV-produced electricity prices that Germany had ever experienced, and significantly lower solar PV-produced electricity prices than the European market is accustomed to. The winning bids in the tender were €53.80/MWh, i.e., €20/MWh lower than the €72.50/MWh observed in Germany during the earlier PV tenders.

The main criticism of the scheme was the differing tender conditions between the two countries. For example, unlike Germany, developers in Denmark were allowed to construct PV arrays on agricultural land (Consequently all new projects from this tender will be built on agricultural land). Another example is the favourable taxation regime in Denmark as compared to Germany. As a result, the scheme was met with heavy criticism from Germany’s renewables sector, led by BEE [Germany’s renewables foundation], over the distorted competitive



landscape (Radowitz, 2016b). This is even more understandable given that Danish utilities won all of the available tenders for the 20MW Danish auction too.

5.4.1.6 CONCLUSION

From the perspective of the European Commission, the joint PV auctions could be considered a positive outcome in terms of achieving the goals of the Directive 2009/28/EC. In this particular case, joint auctions were able to drive down solar PV-produced electricity prices thereby helping solar PV become more competitive than earlier. As a first of its kind, the scheme also showed that coordinated support systems in the form of auctions could work in the European context. However, whether the two countries replicate this process remains to be seen, especially in the context of disharmony between the tendering conditions and rules between the two countries.

Key takeaways from the meshed offshore wind perspective from Case Study A:

- Cooperation mechanisms can be effective at reducing electricity costs.
- Cooperation mechanisms can operate alongside existing national schemes.
- Cooperation mechanisms have a greater likelihood of long-term success if there is a level playing field for stakeholders of all the participating countries.

5.4.2 CASE STUDY B: SWEDEN/NORWAY JOINT SUPPORT SCHEME

5.4.2.1 INTRODUCTION

The Joint Support Scheme that has been implemented between Sweden and Norway is the first example of such a certificate scheme within the EU. Sweden has had a renewable certificate market since May 2003. It was expanded to include Norway on 1 January 2012 with the aim of developing sufficient capacity to reach a combined generation target of 28.4 TWh by the end of 2020. The market was expected to be the key driving factor in determining the most efficient locational and temporal pathway at reaching the stated joint policy goals. Moreover, for Sweden, the benefits would include lower support costs, while Norway would benefit from joining an existing support scheme and have more installed RES capacity developed in their country (European Commission, 2014b).

5.4.2.2 OVERVIEW OF THE JOINT CERTIFICATE MECHANISM

The market participants are required to open an electricity certificate account to trade on the certificate market. These accounts are part of the national electricity certificate register. In Norway, this register is called NECS, and in Sweden, its register is known as CESAR. The certificates that are issued to power producers for the renewable electricity that they generate are credited to the company's electricity certificate account. The certificate trade between buyers (market parties with quota obligation) and sellers (renewable power producers) occurs bilaterally between the two market parties with the transfer of shares between the accounts of the two involved parties. The trade may also take place via brokers.



The annual energy report of the Swedish-Norwegian certificate market (NVE & Energimyndigheten, 2015) provides a step-wise description of the functioning of the electricity certificate market as described below:

- I. The renewable power producers receive one electricity certificate per MWh of renewable energy generated. They may receive these certificates for a maximum period of 15 years.
- II. On the demand side, the requirement of renewable certificates is created due to laws that make it incumbent on specific consumers and electricity suppliers to buy electricity certificates. The quantity of electricity certificate required is administratively calculated in proportion to their electricity consumption level using a predefined formula.
- III. These certificates are traded on the electricity market between entities with quota obligations and renewable power producers that have received the certificates. The demand for and supply of certificates set the market price.
- IV. Eventually, the costs from the certificate market are passed on to the end user by the electricity supplier.
- V. Each year, entities that have quota obligations must achieve their quota obligation by cancelling a sufficient number of their electricity certificates.

5.4.2.3 RATIONALE

It can be argued that the Renewable Energy Directive may not have been the real driving force behind the creation of the Sweden/Norway Joint Support Scheme. The joint project between Sweden and Norway was envisioned years much before the introduction of cooperation mechanisms in the Renewable Energy Directive. It is conceivable to imagine that this joint support scheme would have materialised even without the push from the Renewable Energy Directive, as other considerations such as cost efficiency were taken into account while envisioning this scheme rather than only reaching the goals of the Renewable Energy Directive. (Kampman et al., 2015).

5.4.2.4 PERFORMANCE

Since the implementation of the joint certificate scheme, 13.9TWh of renewable generation capacity has been added between 2012-2015. No doubt the joint support scheme was one of the key driving forces behind this growth in penetration of renewable energy in Norway and Sweden.

However, news media reports (Starn, 2016) indicate that Norway announced plans to quit the joint support scheme at the end of its current tenure in 2020-21. Nevertheless, units that have contracts until 2035 will continue to receive certificates as per the current agreement between the two countries on the support scheme.

According to media reports from April 2017 (Bellini, 2017; RenewableNow, 2017), Norway's Ministry of Petroleum and Energy announced the continuation of the joint support scheme until 2030. The announcement followed an extended period of intense negotiations between the two member states. According to the new agreement, Sweden will add another 18TWh in addition to its 2020 targets by 2030 while Norway's target will remain unchanged. Norwegian plants that would be permitted to participate in the scheme must be commissioned by 2021 (RenewableNow, 2017).



Norway's reluctance to continue with the joint certification scheme can be attributed to several factors, the most immediate being that the scheme resulted in asymmetric investments in new renewable electricity capacity between Sweden and Norway. At the start of the Joint Support Scheme, Norway aimed to add capacity to generate 13.2 TWh out of the planned 2020 target of 28.4 TWh. However, according to news media reports in 2016, 84% of the total new production of renewable energy (14TWh) added since the start of the joint support schemes came from generation units that were based in Sweden (Starn, 2016).

The impact of the joint support scheme on disproportionality of investment becomes even starker when one compares the potential for wind development between the two countries. The theoretical potential for wind development in Norway's coastal region is considered far superior to that in Sweden. Thus it was expected that Norway's wind potential would be exploited before that of Sweden (European Commission, 2014b). However, as of December 2015, only 24 wind farms with a total production of 2.5TWh have been built in Norway (compared to a total production of 143.4TWh) (Adomaitis and Heneghan, 2016).

It can be argued that considering the aforementioned numbers, the joint scheme resulted in a more favorable outcome for Sweden as compared to Norway. Nevertheless, we must keep in mind that there were several other factors that were in part responsible for the pattern of wind power development observed across the two countries. Investment conditions in Sweden were more beneficial compared to those in Norway. The developers and investors were far more familiar with the rules established for the support scheme, as well as with the straightforward planning rules. Finally, the less mountainous terrain in Sweden led to lower connection costs (Kampman et al., 2015).

Norway's problems were further compounded by the fact that the surge in Swedish wind power production led to a 56% fall in the Nordic year-ahead power prices, causing Norway's dominant hydro producers to face a decrease in their margins (Starn, 2016).

5.4.2.5 CONCLUSION

As mentioned earlier, it can be argued that the Renewable Energy Directive may not have been the real driving force behind the Sweden/Norway Joint Support Scheme as it was envisioned years before the introduction of cooperation mechanisms in the Renewable Energy Directive. Nevertheless, the Norway – Sweden joint certificate scheme is the first of its kind in Europe. It can be considered a success in the context of implementing and administering a joint support scheme, and is thus a success in terms of the Renewable Energy Directive 2009.

However, Norway's reluctance to continue with the scheme does provide a different picture. The disproportionate investment in renewable capacity between the two countries did reveal a weakness of this scheme in balancing the divergence between investment efficiency and national goals. Participating countries may decide to discontinue such schemes if national interests are not met.

It can be observed that for the long-term success of such a scheme, it is necessary to ensure that a fine balance is struck between these two elements. One of the main barriers to effectively implementing cooperation



mechanisms appears to arise from the difficulty in creating the equality of opportunity and provision of an equal playing field for stakeholders in both collaborating countries. One way to attain this level playing field could be with greater harmonisation of market conditions in participating countries. It should be noted that a different joint support scheme mechanism other than a joint certificate market may also provide a different outcome.

As a technology-neutral mechanism, the joint green certificate mechanism has been criticised as being an inefficient mechanism for promoting offshore wind investments, considering that costs are 40-50% higher than onshore investments (Jacobsson et al., 2013). Also, the TGC mechanism increases uncertainties for the investor, as revenues coming from the support are volatile, changing in function of the quota levels.

Key take away from the meshed offshore wind perspective from case study B

- As a technology-neutral mechanism, the joint green certificate mechanism has been criticised as being an inefficient mechanism for promoting offshore wind investments
- EU Commission targets and national interests do not always converge.
- Thus, countries may leave collaboration mechanisms if they feel membership is not in their national interest

5.5 CONCLUSION

The effectiveness of renewable support schemes would have a large bearing on investment in and the development of offshore wind farms in countries surrounding the North Sea. Cooperation between countries surrounding the North Sea could be one type of initiative for encouraging the development of offshore wind infrastructure in this region. This would consequently have a significant impact on the development of transmission infrastructure over the North Sea as well. Therefore, the main aim of this deliverable is to provide the reader with a multi-dimensional and holistic overview of the topic of renewable support schemes and cooperation mechanisms for renewable support from a meshed offshore wind development perspective. The case studies provide an insight into the experience of implementation of such schemes. This experience will be useful in enabling effective cooperation mechanism if countries decide to follow this path in the coming years.

In the context of the renewable support schemes being implemented in the countries of the North Sea, it can be observed that there is a clear trend away from an out of the market feed-in tariff system to a feed-in premium system. 50% of the countries that are under consideration in this report have explicitly implemented a feed-in premium scheme while France too has moved to a feed-in premium system for specific technologies. Belgium, which utilises a renewable obligation scheme, provided an interesting case, in which the prices for offshore wind renewable certificates are treated such that they resemble a feed-in premium scheme. However, the method of administration of the feed-in premium may vary from country to country. Technology-specific competitive auctions are the most commonly used mechanisms for calculating the level of support or the value of feed-in premium that is required to be provided to the developers.

It should be noted that Norway and Sweden continue to use a joint renewable obligation (renewable certificate) scheme for support. This is the also the first example of implementation of such a joint mechanism. From an

offshore wind development perspective, however, technology neutral renewable obligations appear to have a limited positive impact on the development of offshore wind farms.

In the context of harmonisation of renewable support schemes among these nations, the shift towards a feed-in premium can be considered a welcome move. Whether this evolution leads to greater coordination between these nations in administering renewable support (even leading to a cooperation mechanism between multiple nations) and if so, then what type of mechanism, remains a wide-open question.

In a meshed offshore system, unharmonized national support mechanisms may not be able to provide efficient incentives. Cooperation mechanisms for renewable support may be a solution. Three cooperation mechanisms for renewable support schemes namely; statistical transfers, joint projects, and joint support schemes, were introduced by the EC as part of the Directive 2009/28/EC. The aim of introducing these alternatives for cooperation was to encourage and enable greater cross-border cooperation between member states on renewable energy policies. However, cooperation mechanisms for renewable support have rarely been utilised by the EU states.

According to current literature, a statistical transfers mechanism is easy to implement, can work in parallel with national support schemes, is technology neutral and would aid in reducing the cost of renewable support for the ‘seller’ countries. However, it does not provide any additional incentive apart from the national renewable support scheme for investment in new projects. Thus, the scheme is dependent on the pro-activeness (and ability) of the participating countries in developing excess renewable resources to trade. This dependence and the ex-post nature of the scheme creates a risk that member states which depend on statistical transfers for reaching their targets may not find enough sellers if the market is not sufficiently liquid. Thus, the use of stand-alone statistical transfers as a cooperation mechanism may not be an effective alternative for encouraging the development of meshed offshore wind.

Joint projects may improve cost efficiency, encourage technology development, improve the security of supply for the countries involved and act as a launch pad for long-term collaboration. However, due to overlaps between such arrangements and the national support mechanisms, there is a risk that such projects may reduce the effectiveness of the national support schemes.

The main argument in favour of applying a joint support scheme is that it would improve the overall efficiency and the most economically viable sites would eventually be developed. Secondly, unlike national support mechanisms, joint support schemes would enable development of projects outside national borders. Although cost optimisation of renewable support is crucial, a holistic perspective must be taken while selecting and implementing any joint support scheme. Furthermore, development of the most cost-effective locations for renewable exploitation over the entire region may lead to a skewed distribution of the installed capacity over the territories of the involved countries. Therefore, there is a risk that the individual national goals may not be met.

In the context of meshed offshore wind development, the implementation of a technology-specific joint support scheme appears to be a relevant alternative to consider for further discussion. Such a scheme would enable



greater harmonisation in the support for the offshore wind farms. It would also lead to the development of the most cost-effective sites. Assuming the utilisation of an efficient method for calculating costs and benefits, this support scheme would aid in enabling a more balanced allocation of the costs and benefits between countries connected to the meshed system. Making the support scheme offshore specific could enable implementation of this scheme alongside the national support schemes while minimising negative cross-policy impacts.

Considering the evolution of the support schemes in the countries around the North Seas, an offshore specific feed-in premium administered through a competitive auction appears to be a good starting point for developing a “technology-specific joint support scheme”.

It can be inferred from the case studies presented that cooperation mechanisms have a higher likelihood of long-term success if there is a level playing field for stakeholders of all the participating countries. Importantly, cooperation will be most suited where similar market conditions exist within the cooperating states. An important roadblock while implementing joint support schemes observed is that EU Commission targets and national interests do not always converge. Thus, countries may leave cooperation mechanisms if they feel that membership is not in their national interest.



6 OFFSHORE GRID INVESTMENT II: TRANSMISSION TARIFF DESIGN IN A MESHED OFFSHORE GRID CONTEXT

6.1 INTRODUCTION

The Position of this chapter in the overall scheme of this report structure has been presented in Figure 29.

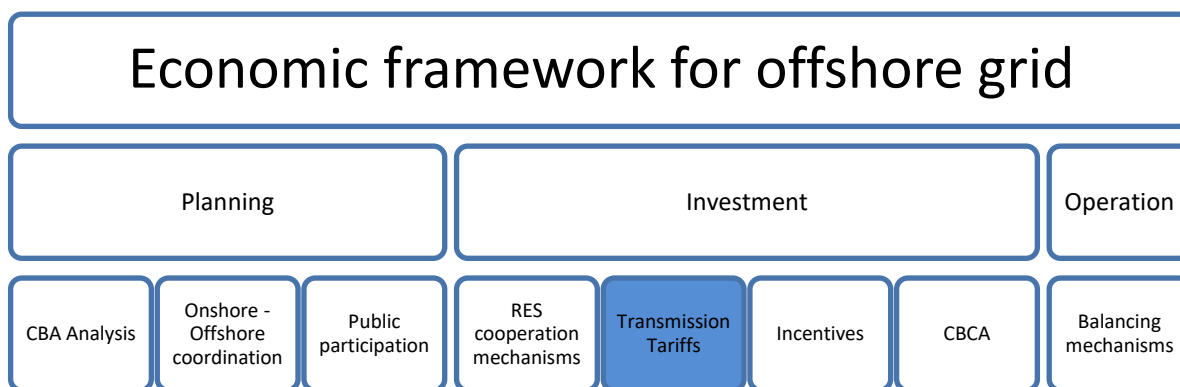


Figure 29: Illustration of the position of this chapter in the overall report structure.

According to the report prepared for the European Commission by Delhaute et al. (2016), transmission tariff design is expected to have an impact on the development of offshore wind farms (OWF). Although transmission tariff represents only a smaller fraction of the total costs of an OWF project, it may have an impact on the location and business case of these projects. For example, if the methodology of calculating transmission tariff in a location imposes an additional risk to the developer, the developer may prefer to move to a different location with a more favourable tariff structure, under the assumption that other parameters such as support schemes, market design, and wind availability are similar. ACER has explicitly expressed its concerns regarding the unharmonized transmission tariff methodologies in Europe, especially about tariffs for producers (ACER, 2015b, 2015c).

In this chapter, first, we provide the reader with an understanding of the theoretical aspects of transmission tariff design. This is followed by an analysis of the level of transmission tariff regime harmonisation between the different countries of the North Seas.

6.2 TRANSMISSION COST ALLOCATION METHODS

The transmission of electricity is an activity that is characterised as a natural monopoly, and therefore the revenues of the transmission system operators are regulated by National Regulatory Agencies (NRAs). Independent of the regulatory model being used, whether it is a cost-plus approach or incentive regulation approach, costs would eventually be recovered from grid users which can be both generation and load.

Subsequently, various approaches for allocating these costs have been used in practice and been proposed in the literature.

The cost of transporting electricity from generators to consumers can be separated into two components. The first one is the cost of the infrastructure itself (i.e. investment, operation, and maintenance), and the second is the cost incurred due to the existence of the given infrastructure (e.g. losses, generating rescheduling due to network constraints and ancillary services) (Lévêque, 2003). These two components should be allocated in such a way that it provides an economically efficient investment signals and, at the same time the costs are allocated to the beneficiaries.

The cost incurred by TSOs due to the existence of the infrastructure can generally be recovered using market mechanisms, such as auctioning for limited capacities. An alternative option is the use of nodal pricing, which not only enables the recovery of the “use of the grid” costs but also sends an efficient short-run economic signal (Lévêque, 2003). In theory, congestion management by either auctioning or nodal pricing will generate revenues for the TSO that can be used to recover the cost of the infrastructure. Nevertheless, as shown by Marin et al. (1995), in reality, these revenues may be far from sufficient to recover the cost of the infrastructure. This is mainly due to the lumpy characteristic of transmission investments and because these investments are not made exclusively to increase capacity, but for several other reasons such as improving the security of supply, integrating renewables, etc. (Pérez-Arriaga, 2013). Consequently, the unrecovered part of costs must be recovered by the application of another charge, called Complementary Charges (CC).

The CC can be further subdivided into Connection Charges and Use of the System Charges (UoS). The former is a user-specific type of charge, in which users pay part (or entirety) of the investment for which they are exclusively responsible as there is a clear cost causality. This may consist of their connection to the main grid and possibly the cost of necessary reinforcements. The latter, the UoS are generally known as *transmission tariffs*.

There are two main aspects that are key to ensuring an effective and efficient design for transmission tariffs. The first aspect is the distribution of transmission costs between the different grid users (the “*how much*” question) and the second is the form of recovery of these costs (the “*how*” question). Finally, in an interconnected system such as the EU, the cross-border coordination between TSOs for allocating transmission costs is critical for the success of the overall transmission cost allocation.

Tracing meshed offshore grid costs: from CBA to Transmission Tariffs

A meshed offshore grid will be achieved by the joint investment in transmission lines, as is the case for interconnectors nowadays. Each of these assets has a cost that eventually must be recovered from its users. Considering the multi-party characteristics of these assets, their costs may follow a more complicated path until they reach the final user.



As explored by the PROMOTioN WP7.2 Internal Deliverable 7.2.1, the Cost-Benefit Analysis (CBA) is the tool used to identify efficient investments. The CBA is expected to provide decision-makers with geographically disaggregated costs and benefits.

Consequently, a Cross-border Cost Allocation (CBCA)⁷¹ process is conducted, in which costs are split among parties. Usually, these costs are split based on the information contained in the CBA. However, they may also be influenced by the negotiation among parties.

Once the CBCA is agreed upon, the asset is included in the TSO's Regulatory Asset Base (RAB)⁷². The TSO then starts to recover these costs from the users via the transmission cost allocation methods discussed in this report.

In a brief summary, the CBA identifies costs and benefits, the CBCA divides costs among parties, and transmission allocation methods divide costs once more, now among users.

6.2.1 ALTERNATIVES FOR TRANSMISSION COSTS DISTRIBUTION AMONG GRID USERS

The methods for transmission cost distribution can broadly be divided into three groups: economic methods, network utilisation methods and methods without locational components (I. J. (Editor) Pérez-Arriaga, 2013).

6.2.1.1 ECONOMICALLY BASED METHODS

In these methods, transmission tariffs are designed based on the cost causality principle. According to this principle, the cost of building a new infrastructure should be allocated to those users that make the construction of this new infrastructure necessary. Therefore, users should be charged only for the use they make of the grid.

The primary method in this category is called the “Beneficiary pays” method. In this method, the benefits from the construction of new lines for each user are calculated. The costs are then allocated relative to the benefit accrued by each user. In this case, benefits are defined as the “financial impact for a grid user associated with the existence of a grid facility or suite of facilities” (I. J. Pérez-Arriaga, 2013). The benefits from the new line are therefore the incremental change in benefit for the user due to the existence of the new facility as compared to the pre-existing situation. As one can expect, the difficulty with this method lies in assessing the benefits for existing lines, as many assumptions and information are needed. In practice, this method has been used for developing regulations adopted in Argentina and California (I. J. Pérez-Arriaga, 2013).

⁷¹ Cross-border cost allocation for a full discussion of this topic will be presented in the upcoming PROMOTioN WP7.2 Internal Deliverable on CBCA.

⁷² Considering the investment is made by a TSO. Note that merchant lines are also possible.

6.2.1.2 NETWORK UTILIZATION METHODS

Since economic benefits are hard to compute, some methods use a proxy for the benefits instead, namely the usage of the network. The first method in this category is the “contract path”. It is a fairly rudimentary method that has been used more in the past (I. J. Pérez-Arriaga, 2013). In this method, the seller and the buyer of electricity agree upon the most logical path for the energy flow thus the cost is allocated in accordance with this agreement. The “contract path” method is therefore based on commercial transactions rather than the actual energy flows. The main critique of this method lies in the fact that energy flows (the real cause of transmission costs) are independent of commercial transactions. Thus the method may not reflect the actual costs and lead to inefficient allocation of costs. This is especially true for meshed networks.

A second method used for calculating the usage of the network by agents is called “marginal participation”. In this method, costs are allocated based on the marginal effect each user has on the line by a variation of 1 MW in its consumption or production (Rubio-Odériz, 2000). For technical reasons, however, this variation will always depend on the choice of a reference node in the system, and therefore results may change according to this choice. A third method for usage computation is the “average participation” method. In this method, a heuristic rule is used to “determine the fraction of the flow of each line that can be attributed to each generator” (I. J. Pérez-Arriaga, 2013). In other words, this method is based on the proportionality principle, as illustrated below in the example (See: Figure 30) from Rubio-Odériz, (2000).

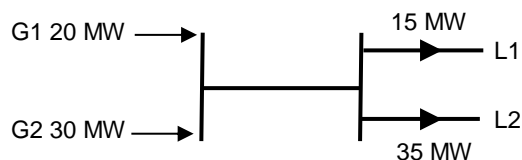


Figure 30: Average Participation Example. Source: Rubio-Odériz, 2000

Following the simple rule of proportionality, generator G1 should be responsible for $15 \times 20/50$ MW of the flow in line L1 and $35 \times 20/50$ MW of the flow in line L2. The same reasoning applies to generator G2.

Other methods for electricity usage calculation are the “Aumann-Shapley” method and the “Long Run Marginal Cost” (LRMC) method. The former is an optimisation/game-theoretic approach, while the latter is a “based on the circuit flows resulting from a given generation-load pair, and on the network superposition property” (Junqueira et al., 2007).

6.2.1.3 METHODS WITHOUT LOCATIONAL COMPONENTS

The third category consists of methods that do not include a locational component. That is to say, these methods do not account for cost causality, but merely try to allocate costs of transmission in the least distortive way or in a simple and presumed non-discriminatory way. The most commonly used method of this type is the “Postage

Stamp”. In this method, a uniform rate is applied to all users based on a simple metric such as the capacity connected, or the energy injected or withdrawn from the grid. This is the simplest and most common method used by electric utilities (Orfanos et al., 2011).

Another form of the tariff with no locational component is the “Ramsey Pricing”. In this method, costs are allocated based on the elasticity of users. The method aims to allocate most of the costs to users that are least elastic to energy prices (I. J. Pérez-Arriaga, 2013). This means that in practice, most of the costs will be allocated to consumers, and among those consumers, residential consumers would bear the most costs, as they don’t react to prices as much as industrial consumers.⁷³

G-Charges

Generators are also grid users and thus beneficiaries of transmission lines. Therefore they too should be responsible for the cost incurred for developing the grid. However, G-charges are often seen as unnecessary, as the cost will be passed to the consumers anyway. Nevertheless, this is not entirely true, as argued by Pérez-Arriaga (2013) and Hirschhausen et al. (2012). Besides recovering the cost of the grid, transmission tariffs can be used to send a locational signal for the siting of new capacity. Therefore, G-charges will be internalised in the investment decision of developers leading to efficient siting of the new capacity from a grid development perspective.

In fact, opinions diverge when it comes to the best format for charging the generators. More specifically in the case of wind farms, the EWEA (2016) recently issued a position paper in which it is argued that locational and power based G-charges tend to penalize wind power plants as the location of the wind farms is based on the availability of resources, and not on the proximity to the load centres. The output of a wind farm is usually a fraction of its installed capacity; thus, the use of a capacity-based charge would penalise such a generator.

On the other hand, a charge based on the installed capacity is less market distortive than a charge based on electricity production, as it is a fixed cost and will not impact the bidding of agents on the market.

6.2.2 DIMENSIONS OF RECOVERING TRANSMISSION COSTS FROM GRID USERS

Once the “*how much*” is defined, the next step is designing the format for recovering this tariff from the user. Even in this case, several options have been used in practice and discussed in theory. These extend from the type of charging (if energy or capacity-based) to periodicity of the charge. These designs could have an impact on agents’ decisions, thus making them a critical part of tariff design.

The critical dimension of transmission cost recovery is the metric that would be utilised to charge the users. It can be an energy-based charge (€/MWh), capacity-based charge (€/MW), a fixed (access-based) charge (€) or a combination of these options. Each one of these formats will have different implications on agents’ decisions, in particular for generators. An energy-based tariff would lead to additional variable costs for the generators,

⁷³ Although this assumption might become obsolete in the near future, see e.g. Schittekatte et al. (2017)

changing their competitive position in the spot market. On the other hand, a capacity-based charge will add a fixed cost for the generator, and it could have an impact on investment decisions in new capacity (I. J. Pérez-Arriaga, 2013).

Another dimension that is relevant specifically in an “energy-based charge” system is the temporal dimension. The tariffs charged to a user can be based on the time of use (Hirschhausen et al., 2012). For example, tariffs can be differentiated within the day (peak, off-peak) or between seasons (summer, winter).

Finally, the periodicity of charge updates is also a relevant aspect. Pérez-Arriaga (2013) argues that tariffs should be calculated ex-ante and not updated for a reasonable period of time (I. J. Pérez-Arriaga, 2013). In this way, signals are stable and predictable, which is extremely desirable from the perspective of investment decisions. On the other hand, if tariffs are not updated regularly and flow patterns are evolving fast, the cost causality principle can be difficult to apply.

6.2.3 INTER-TSO COMPENSATION MECHANISM

The task of allocating transmission costs becomes even more complicated in interconnected systems with different regulatory regimes, as is the case in the European Union.

Before the liberalisation of the power sector in Europe, users had to pay a tariff fee in cross-border power transaction (Hirschhausen et al., 2012). This resulted in the so-called “tariff pancaking”, as at every border a different fee would be charged. This was considered as a barrier to the development of an integrated European electricity market and thus brought into focus the need for a harmonised cross-border tariff mechanism.

In response, an Inter-TSO Compensation Mechanism (ITC) was created. Initially the inter-TSO compensation mechanism was implemented on a voluntary basis and was later transformed into a mandatory instrument. The ITC preserves a “single system paradigm” for network users (Olmos and Pérez-Arriaga, 2007), meaning that transmission tariffs are only paid in their country of origin, but they give access to the whole European grid. The ITC serves then as a balancing mechanism for countries, in which they receive *compensation* for the use of their network by external agents and conversely, pay a *charge* for the use they make of other countries’ networks. In the end, a *net payment* is computed for each country, either positive or negative. It should be noted that alternatively, a pan-European system of transmission tariffs could be an alternative solution for cross-border coordination of transmission tariffs, as it was considered before the implementation of the ITC (Olmos and Pérez-Arriaga, 2007).

6.3 NORTH SEA COUNTRIES’ MAPPING

In this section, we map and analyse the level of harmonisation in the methods of transmission cost allocation adopted by different countries of the North Sea, with particular focus on their transmission tariffs. In this analysis,

we compare ten countries: Belgium, Denmark, France, Germany, Great Britain, Ireland, the Netherlands, Northern Ireland, Norway, and Sweden.

For each country, seven relevant dimensions of transmission charges were analysed. The information presented in this section is based on the ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2016 (ENTSO-E, 2016). This report is produced yearly by ENTSO-E and contains key information on transmission tariff structures across Europe. Further details come from the other reports and the websites of various TSOs.

The Dimension of transmission charges under consideration:

- **G-L charges** The proportion of network costs allocated to generation (if any) and load.
- **Type of connection charges:** Deep charges are characterised by users paying the connection to the main grid and for the necessary reinforcements. In a shallow charge, users pay only for the connection to the main grid. In a super-shallow, the TSO or a third-party is responsible for the connection. It is important to note that in some countries, connection charges differ among users. In this report, we focus only on the connection charge regime used for offshore connections.⁷⁴
- **Temporal price signal:** Consideration of the time of use in tariff design to indicate the difference in usage level of the network at a certain period of time (e.g. the existence of time of use price signal based on periods of congestion). These different periods may be within the day (e.g. peak, shoulder and off-peak) or for different seasons of the year (e.g. summer, winter).
- **Locational price signal:** Consideration of Whether considers the location of use in the tariff design to indicate the difference in usage level of the network in a particular area. The locational signals may come from the application of a network utilisation method, or be based on a simpler metric such as distance from a certain point.
- **The inclusion of losses:** Consideration of losses in the tariffs.
- **The inclusion of system services:** Considering inclusion of system services such as ancillary services and balancing energy in tariffs.
- **Energy-related and capacity-related components:** Proportion in which transmission costs are recovered via energy-based components (€/MWh), capacity-based components (€/MW), fixed components (€) or a combination of the three.

As shown in the detailed description below, the ten countries have very different transmission cost allocation practices, which can lead to different investment and operational decisions. An aspect that draws one's attention is the difference in transmission costs allocated to the generator (G-charge). On one hand, some countries apply a very low (or none) G-charge and a super-shallow connection cost, meaning that very few of the transmission costs will be recovered from generators, and that the costs are almost entirely levied on consumers. On the other hand, some countries have a higher G-charge and can even have a deep connection cost. In these cases, generators will have to bear a greater part of the transmission cost recovery.

⁷⁴ For a discussion on connection charges please see the chapter on "Coordinating offshore-onshore grid planning"

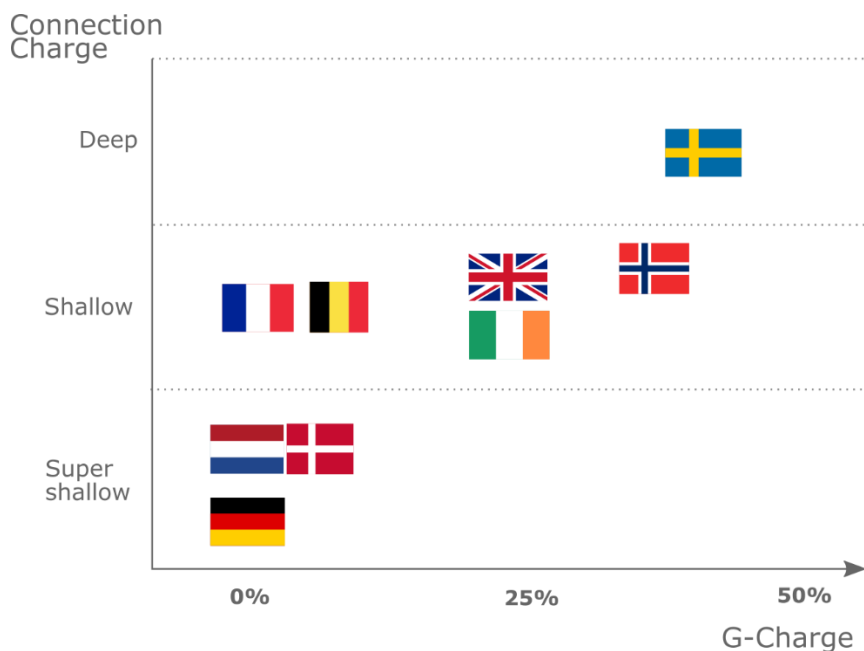


Figure 31: Transmission Costs Levied on Generators

6.3.1 BELGIUM

Belgium allocates 93% of the transmission costs to load and 7% to the generators. Regarding locational price signal, Belgium does not differentiate tariffs according to the location of agents. Losses are only included in the tariffs to the networks below 150kV. The losses from networks with higher voltages are paid by agents according to the percentage of net offtakes, and differentiated for peak hours vs. off-peak hours (Elia, 2017a). Costs of ancillary services, such as reactive power, power reserves, and black-start based (Elia, 2017a) are included in the transmission tariff.

On connection costs, Belgium applies mostly a shallow charge. For onshore connections, everything is socialised, except installations between the grid user and the substation and the connection bay at the substation (ACER, 2015c). For offshore connection, the Belgian TSO Elia is responsible for bearing up to 25 M€ of the cable cost from farm to shore (Jong, 2008).

Table 13: Summary of the transmission tariff structure in Belgium.

G-L charges	G: 7%; L: 93%
Temporal price signal	Yes
Locational price signal	No
Inclusion of losses	No
The inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Shallow

6.3.2 DENMARK

Denmark charges a small portion of transmission costs to generators. They are responsible for 3% of the costs, while consumers bear 97%. Tariffs for consumers are divided into three types: grid tariffs, system tariffs and Public Service Obligations (PSO). In the second semester of 2016, they summed up 32.9 øre/kWh, and the PSO tariff accounts for 75% of this total. The tariff for producers, however, is only 0.3 øre/kWh. Wind turbines and local CHP units that remain subject to purchase obligation are exempt from the grid tariff, according to the Danish TSO Energinet.dk (Energinet.dk, 2016).

Denmark applies no seasonal price signal nor locational signal for transmission charging. However, losses and system services are included in the tariff charged by the TSO. The tariffs are energy-based. The connection cost is super shallow to partially shallow, but for the most relevant portion of offshore projects, a super-shallow approach is used⁷⁵.

Table 14: Summary of the transmission tariff structure in Denmark

G-L charges	G: 3%; L: 97%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
The inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Super-Shallow

6.3.3 FRANCE

France charges only generators connected to the 150 – 400kV grid through an energy-based tariff. The proportion of transmission costs borne by generators accounts for 2% of the total (ENTSO-E, 2016). It's interesting to note that France has five different temporal charges: summer/winter, mid-peak/off-peak, and peak hours. These temporal differentiations are applied to voltage levels below 350 kV. For higher voltages, just the usage duration is considered. No location differentiation is applied, however. One aspect to note is the difference in connection charges depending on the type of agent. Generators pay 100% of their connection to the substation, while consumers pay 70% of their main connection, network development costs due to RES integration are mutualized on a regional basis (ENTSO-E, 2016).

Table 15: Summary of the transmission tariff structure in France

G-L charges	G: 2%; L: 98%
Temporal price signal	Yes (5 types)
Locational price signal	No
Inclusion of losses	Yes

⁷⁵ For more information, please see the Deliverable 7.2.1 - Coordinating Onshore-Offshore grid planning

The inclusion of system services	Yes
Energy-related and power-related components for G	Energy-based
Type of connection charges	Shallow

6.3.4 GERMANY

Germany applies no transmission tariffs to generators. All transmission costs are borne by consumers in a non-temporal and non-locational dependent tariff (Wilks and Bradbury, 2010). Regarding connection charge, the ENTSO-E report classifies it as shallow to super-shallow, as grid users pay for their connection line and substation (ENTSO-E, 2016). For offshore wind farms, however, the connection cost is super-shallow. The developer doesn't pay for the line, and the cost is socialised by the TSO (Fitch-Roy, 2016). Losses and system services are included in transmission charges.

Table 16: Summary of the transmission tariff structure in Germany

G-L charges	G: 0%; L: 100%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
The inclusion of system services	Yes
Energy-related and power-related components for G	-
Type of connection charges	Super-shallow

6.3.5 UNITED KINGDOM⁷⁶

6.3.5.1 GREAT BRITAIN

In GB, the transmission grid is owned, maintained and operated by three Transmission Operators (TOs), while the system in its entirety is operated by a single System Operator (SO). Costs of transmission are levied as 3 different charges: connection charges, Transmission Network Use of System (TNUoS) charges and Balancing Services Use of System (BSUoS) charges.

Connection charges in GB are considered shallow (ENTSO-E, 2016). Both load and generation are responsible for paying for their connection to a substation if the asset is to be used exclusively by the new entrant. The TNUoS is paid by all users of the transmission network, including generator, the only exemption being interconnectors (Ofgem, 2015a). These charges are differentiated by location to reflect the costs that the users impose onto the grid. The SO also recovers the cost of balancing the system through the BSUoS. Losses are not included in the transmission charges.

⁷⁶ We differentiate UK into two parts: Northern Ireland and Great Britain.

Table 17: Summary of the transmission tariff structure in the GB

G-L charges	G: 23%; L: 77%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	No
The inclusion of system services	Yes
Energy-related and power-related components for G	Capacity-based
Type of connection charges	Shallow

6.3.5.2 NORTHERN IRELAND

Northern Ireland follows a similar approach to the rest of the UK and Ireland. Currently, 75% of costs are borne by consumers, and the remaining 25% is paid by generators in a capacity-based charge. The Transmission Use of System (TUoS) paid by users comprises three components: Network Charges, System Support Services and Collection Agency Income Requirement (SONI, 2017). These components are responsible for recovering the use of the network infrastructure, the system services (including ancillary services) and to balance revenues of the Moyle interconnector, respectively. The System Support Services and Collection Agency Income Requirement are not levied on generators, only on consumers. Connection charges are shallow. Both consumers and generator over 1MW of installed capacity pay 100% of the connection to the main grid (Entso-E, 2016).

Table 18: Summary of the transmission tariff structure in Northern Ireland

G-L charges	G: 25%; L: 75%
Temporal price signal	Yes
Locational price signal	Yes
Inclusion of losses	No
The inclusion of system services	No
Energy-related and power-related components for G	Capacity based
Type of connection charges	Shallow

6.3.6 IRELAND

The generators in Ireland pay 25% of transmission costs, while consumers bear 75% of the total. Users have levied a Transmission Use of System Charges (TUoS). This charge is meant to recover two components: costs for the use of transmission infrastructure and costs arising from the operation and security of the transmission system (Eirgrid, 2015). The TUoS is divided into three categories: Demand Transmission Service (DTS), Generation Transmission Service (GTS), and Autoproducer Transmission Service (ATS). Generators are also entitled to pay both network charges and system services associated with their injection of electricity into the grid and periodic withdrawal for consumption by start-up and standby equipment (Eirgrid, 2015). The connection costs in Ireland are considered shallow. Demand pays 50% of the connection while generators pay 100% (ENTSO-E, 2016).

G-L charges	G: 25%; L: 75%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	No
The inclusion of system services	Yes
Energy-related and power-related components for G	Capacity based
Type of connection charges	Shallow

6.3.7 THE NETHERLANDS

According to TenneT, the Dutch TSO, users of the transmission grid pay both connection tariffs and transmission services tariffs (TenneT, 2017a). Connection tariffs are divided into two parts: initial connection tariff and periodic connection tariff. The initial connection tariff is the cost of building the line from the user to the grid. This connection charge is identified by ENTSO-E (2016) as shallow. However, as identified in Chapter 3, the connection regime for offshore power plants is super-shallow. Besides the initial connection charge, users must pay a periodic connection tariff, meaning the cost of maintaining and eventually replacing the installation built for the new agent.

The transmission services tariffs, on the other hand, is composed of two other components, namely the non-transmission-related consumer tariff, that includes administrative costs of managing the grid, and the transmission-related consumer tariff, that recovers the cost of transporting the electricity in a capacity-based charge. It is important to note that generators are not charged for transmission costs. Together with Germany, these two countries are the only ones that don't apply a use-of-transmission charge on generators.

Table 19: Summary of the transmission tariff structure in The Netherlands

G-L charges	G: 0%; L: 100%
Temporal price signal	No
Locational price signal	No
Inclusion of losses	Yes
The inclusion of system services	Yes
Energy-related and power-related components for G	-
Type of connection charges	Super-shallow

6.3.8 NORWAY

Transmission tariffs in Norway are based on costs referring to the agent's connection point, and therefore are location specific (NVE, 2017). These tariffs are also determined based on marginal losses. Generators pay 38% of the total transmission costs, which makes Norway one of the countries with the highest G-charge share of the sample of countries. Charges on generators are composed of an energy-based tariff and a fixed component. The latter is a lump-sum paid based on a 10-years historical production average. This amount is calculated every year.

Connection costs are identified by ENTSO-E as being shallow (2016). However, according to NVE (2017), “the generator may be charged related to investments needed to increase the capacity of the existing network”, suggesting a deep approach.

G-L charges	G: 38%; L: 62%
Temporal price signal	Yes
Locational price signal	Yes
Inclusion of losses	Yes
The inclusion of system services	Yes
Energy-related and power-related components for G	Lump-sum + Energy based
Type of connection charges	Shallow/Deep

6.3.9 SWEDEN

Sweden applies a capacity charge to grid users, and it is expected that generators should pay around 30% of the cost of transmission (ACER, 2015b). ENTSO-E (2016), however, estimates suggest that G-charges cover 41% of the regulated cost. This is the highest G-charge share of all ten countries analysed.

The Swedish TSO also applies a very strong locational price signal to users. The transmission charge for generators decreases linearly from North to South, according to the latitude of the user. This is due to general power flow from North to South, and it aims at giving incentives for producers to install their facilities in the South, therefore reducing congestions (ACER, 2015b). Connection charges are deep in Sweden, meaning that users must not only pay for the infrastructure necessary for connecting to the main grid but also reinforcements in the main grid if those are needed.

Table 20: Summary of the transmission tariff structure in Sweden

G-L charges	G: 41%; L: 59%
Temporal price signal	No
Locational price signal	Yes
Inclusion of losses	Yes
The inclusion of system services	Yes
Energy-related and power-related components for G	Capacity based
Type of connection charges	Deep

6.3.10 SUMMARY

The summary shows currently several types of tariff structures across countries, and that there is undoubtedly a lack of harmonisation. Tariffs are different in the form they are charged and in the level of charging, sending varying levels of economic signals to users, especially generators.

Table 21: Summarising transmission charging design in the North Seas

	Share of G-charges	Seasonal Signal	Locational Signal	Losses included	System services included	Type of Tariff for Generators	Type of Connection Charge
Belgium	7%	Yes	No	No	Yes	Energy based	Shallow
Denmark	3%	No	No	Yes	Yes	Energy based	Super shallow
France	2%	Yes	No	Yes	Yes	Energy based	Shallow
Germany	0%	No	No	Yes	Yes	-	Super shallow
Great Britain	23%	No	Yes	No	Yes	Capacity based	Shallow
Ireland	25%	No	Yes	No	Yes	Capacity based	Shallow
Netherlands	0%	No	No	Yes	Yes	-	Super shallow
Northern Ireland	25%	Yes	Yes	No	No	Capacity based	Shallow
Norway	38%	Yes	Yes	Yes	Yes	Lump-sum + Energy based	Shallow
Sweden	41%	No	Yes	Yes	Yes	Capacity based	Deep

6.4 CONCLUSION

In this chapter, the impact of transmission tariff on offshore grids is discussed. A general overview of transmission cost allocation is presented to guide the discussion. The main aspect analysed in this chapter is the impact of transmission tariffs, considering that connection tariffs have already been covered in Chapter 3: Coordinating Onshore-Offshore grid planning.

A mapping of how ten nations adjacent to the North Sea deal with several aspects of transmission tariff design was presented. From this mapping, we can conclude that transmission tariffs are still unharmonized across the countries surrounding the North Sea. Both the amount of transmission costs levied on generation and the form of transmission charges vary considerably. There exists a risk that such a scenario could prove to be detrimental from the perspective of developing a meshed offshore wind infrastructure. It can impact the investment decisions of OWF and therefore impact the overall benefit extracted from the meshed offshore grid. The situation can also impact TSOs if cross-border flows created by the meshed offshore grid are not appropriately compensated. Therefore, greater harmonisation may be required⁷⁷.

⁷⁷ Note that the recent “Clean Energy for All Europeans” package proposes a network code on transmission tariff design.

7 OFFSHORE GRID INVESTMENT IV: ECONOMIC INCENTIVES FOR INVESTMENT IN MESHED OFFSHORE GRIDS

7.1 INTRODUCTION

The Position of this chapter in the overall scheme of this project structure has been presented in Figure 32.

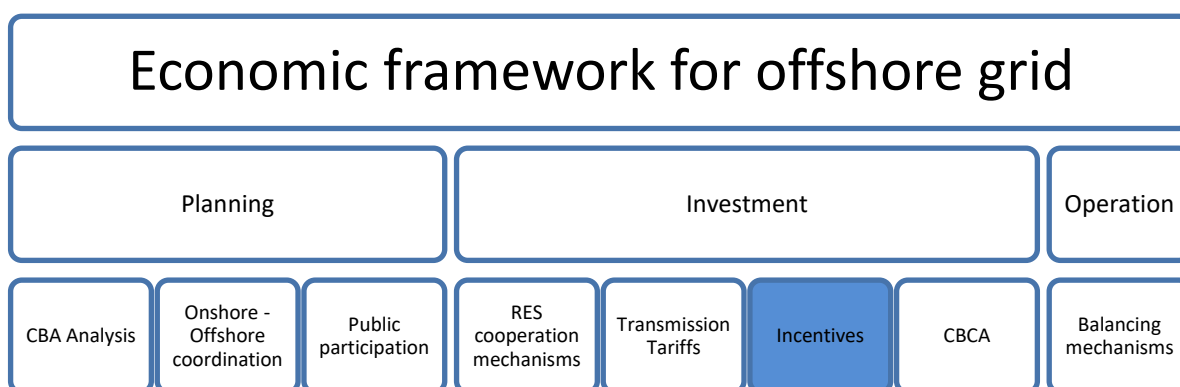


Figure 32: Illustration indicating the position of this chapter in the overall report structure

Since the liberalisation of the power sector, the use of ‘incentive regulation’ has become a standard practice among European regulators. Furthermore, Article 13 (1) of the TEN-E regulation for PCIs mandates the use of dedicated incentives for projects that may be deemed to have higher risks for their development, construction, operation or maintenance. In the past few years, regulators have opted for a case-by-case regulation as a means to incentivise necessary or strategically important investments. Nevertheless, it has not substituted portfolio regulation.

Offshore wind is expected to play a significant role in enabling the EU to meet its greenhouse gas (GHG) reduction and renewable energy target in the near and long-term future. In this context, the development of a robust offshore electricity grid infrastructure has the potential to deliver many benefits. Thus, such investments may be considered ‘necessary or strategically important’.

In this chapter, we investigate the economic incentives that are necessary for the development of the offshore grid. This research extends the work of Glachant (2013), and Meeus and Keyaerts (2014) to present the combined

impact that the general regulatory regime and dedicated incentives may have on the risk and remuneration for TSOs^{78,79}.

A case study approach is utilized to substantiate the analysis. Regulatory structures of Great Britain, Germany, the Netherlands and Belgium are assessed. These five countries were chosen because of their relevance to the development of offshore wind power. As of 2016, they accounted for 97.8% of the installed offshore wind capacity in Europe (See Figure 33). Thus, the analysis of these countries ensuring that the results presented are sufficiently robust and relevant from an offshore wind infrastructure development context.

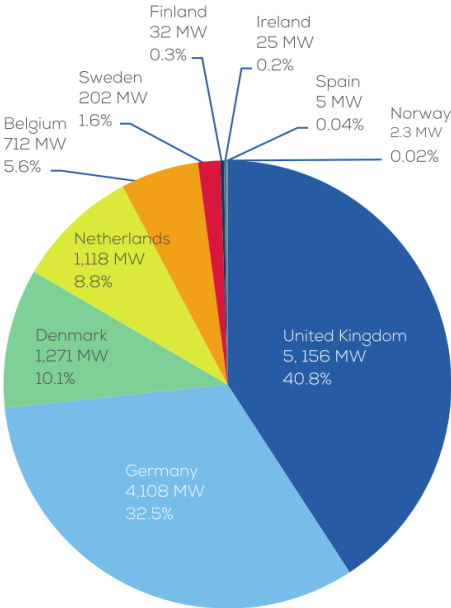


Figure 33: Offshore wind installed capacity (MW) in Europe by country. Source: Wind Europe, (2017)

This chapter is structured as follows. In the next section (7.2) fundamentals of incentive, regulation are discussed. In Section 7.3 the methodology used for assessing the given case studies is discussed in detail. The methodology consists of two parts. The first part contains a study of default national regulatory frameworks; the second, an evaluation of “dedicated incentives” for investments. Section 7.4 consists of three parts. In the first part, the general regulatory regime for each country is assessed based on the analytical framework presented by Glachant (2013). In the second part, dedicated incentives provided in these country cases are discussed. The third part provides a summary and interpretation. Finally, key conclusions are presented in Section 7.5.

⁷⁸ One can argue that not only TSOs invest in offshore transmission infrastructures. Although this is true, our analysis is focused on the TSO, considering that investments on a future meshed offshore grid will be more suitable for TSOs, or at least they are expected to carry the greatest volume of investments in the early stage of a meshed offshore grid.

⁷⁹ Also see: Bhagwat and Lind, (2018)

7.2 REVISITING INCENTIVE REGULATION

7.2.1 WHAT ARE ECONOMIC INCENTIVES

Since the liberalization of the power sector, the use of "incentive regulation" has become a standard practice among European regulators for effective and efficient implementation of the grid task. We discuss three definitions of economic incentives from the literature that appear to be of relevance from the power network industry context.

Firstly, In economic theory the concept of incentives is explained by Laffont and Martimort (2002) as follows:

"The starting point of incentive theory corresponds to the problem of delegating a task to an agent with private information. This private information can be of two types: either the agent can take an action unobserved by the principal, the case of moral hazard or hidden action; or the agent has some private knowledge about his cost or valuation that is ignored by the principal, the case of adverse selection or hidden knowledge. Incentive theory considers when this private information is a problem for the principal, and what is the optimal way for the principal to cope with it. (p. 4)"

The definition above can be translated into the power industry as follows. The regulatory authority is the principal, and the regulated (monopolistic) network is the agent. Indeed, regulators delegate certain activities to network companies, and information asymmetry is created. Therefore, incentives are used by the regulator to steer the actions of network companies towards the desired outcomes in the presence of information asymmetry.

Secondly, ACER (2014b) provides the following definition for regulatory incentives:

"By incentives, the Agency means any regulatory measures, financial, coercive, moral, etc., which aim to motivate a project promoter to take a particular course of action (e.g. commissioning an infrastructure project by a defined deadline). In this recommendation, regulatory incentives comprise risk mitigation regulatory measures and monetary reward or penalty schemes to achieve such purpose."

It is important to note that the passage above highlights the fact that incentives are not only monetary measures. Coercive and moral incentives can also be used by regulators. A typical example of moral incentive is the "sunshine regulation", that is intended to simply "name and shame" bad utilities, thereby creating a moral push for improvement (Decker, 2014).

Finally, the European Commission (2014c) understands incentives as the influence over the risk-reward ratio in order to foster investments:

"In this study, regulatory incentives are defined as mechanisms incorporated in the regulation that facilitate or stimulate investments. The purpose of such mechanisms is to influence the risk-reward

ratio resulting from the regulation. In general, such mechanisms can facilitate or stimulate investments in two ways, namely by mitigating risks for project promoters and/or by increasing rewards for project promoters.”

Combining the statements of ACER and the Commission, *economic incentives*, as described in this deliverable, *comprise risk mitigation regulatory measures and monetary reward or penalty schemes set by the regulator in order to achieve an appropriate risk-reward ratio on an investment by the regulated network company.*

It should be noted that although both ACER and the Commission define the risk mitigation and reward adjustment as “regulatory incentives”. We use the concept of “economic incentives”. Therefore, economic incentives are not to be confused with other drivers for the project developer’s actions. In the meshed offshore grid, many other aspects will lead TSOs to investments or discourage them. For instance, the outcome of the CBA analysis, and later, the CBCA negotiation, may influence the TSO’s decision, as well as legal and financeability conditions. Nevertheless, these are not considered economic incentives here, but exogenous investment drivers to this analysis. They are part of the investment function for the project promoter and considered *ceteris paribus*.

However, there are two classic assumptions that do not hold true in practice. Firstly, it is assumed that the network operator’s entire cost is controlled by the regulator as a whole (Laffont and Tirole, 1993). However, network operators perform several heterogeneous tasks that each require the application of unique regulatory tools, each with advantages and disadvantages (Rious et al., 2008; Sagan et al., 2008; Saplacan, 2008).

Secondly, in practice, regulators may face limitation in their abilities and make decisions in the realm of bounded rationality. Thus, the regulator may not have the necessary cognitive, computational and administrative abilities required to implement the desired regulatory tool effectively.

In this chapter, we revisit incentive regulation to raise public awareness and trust in the context of infrastructure development, discussing how the key regulatory tools of price or revenue cap regulation, cost-plus regulation and output-based regulation are connected to the task that is to be regulated and to the skills, expertise and resources of the NRA and TSO that have to implement the regulatory framework. The second section of this chapter explores how the costs of raising public awareness and trust can be included in these regulatory instruments.

7.2.2 INCENTIVE REGULATION FRAMEWORKS

7.2.2.1 REGULATORY TOOLS

Glachant et al. (2013) originally identified five key regulatory tools that can be applied for regulating the various tasks performed by the system operator. The five regulatory tools identified are cost-plus regulation, price cap regulation, output regulation, a menu of contracts and yardstick regulation. The latter two can be considered sophisticated versions of the other tools and are not discussed further in this chapter.



Cost plus regulation is based on the principle that the regulated firm can recover the costs that are incurred for service provided, including a fair rate of return on the capital invested (Joskow, 2008). This is a relatively simple tool. The regulator ascertains the costs of the network operator by auditing their accounts. These audited costs are then used as a basis for setting the tariff for the regulated service.

Price or revenue cap regulation can be considered as having a greater complexity compared to cost plus regulation. In this tool, the regulator sets a maximum price (or revenue) that the firms can earn for providing a service. This price is set for a fixed regulatory period (Joskow, 2008). Thus, the firm is incentivised to improve its efficiency by reducing the costs over this period to maximise its profit. However, this is not an incentive for the firms to reveal their real costs to the regulator. Therefore, the regulator would need to become better at setting a correct reference price/efficiency factor for regulating the given task. An error in setting the price cap may lead to windfall profits or crippling losses for the network operators

Output regulation focuses on incentivising improvements in the quality of output that it provides (Vogelsang, 2006). The utilisation of such a tool requires a high degree of sophistication in terms of regulator's abilities. In this tool, the regulator links the reward-penalty for the firm to its output based on a set of key performance indicators (KPIs). In such regulation, the firm has flexibility in the approach that it may use to reach these targets.

The menu of contracts is characterized by the provision of a choice of contracts with varying incentive levels that correspond to the cost level for the regulated firm. The regulated firm will thus choose the type of contract based on the information that it has about its own characteristics as well as current and future market conditions. This tool, on one hand, incentivizes the firm to improve its performance by benefiting from its knowledge while on the other hand this information will get revealed to the regulator over time. Thus the dual issues of moral hazard and adverse selection are addressed together (Rious and Rossetto, 2018).

In yardstick competition, the regulator compares the costs and efficiency level of regulated companies to each other and then fix the company's revenue based on benchmark performance. Thus a regulated firm has an incentive to increase its profit by bettering the benchmark.

7.2.2.2 SELECTING A REGULATORY INSTRUMENT TO REGULATE SPECIFIC TASKS

Following Glachant et al. (2013), the appropriateness of these tools for regulating a given task can be assessed based on a framework consisting of two dimensions. These dimensions are the features of the task to be regulated, on the one hand, and the abilities and resources of the regulatory authority, on the other hand. The first dimension consists of three criteria, namely, controllability, predictability and observability of the task. Figure 5 illustrates the proposed decision tree to align tasks, regulatory tools and regulator's abilities.



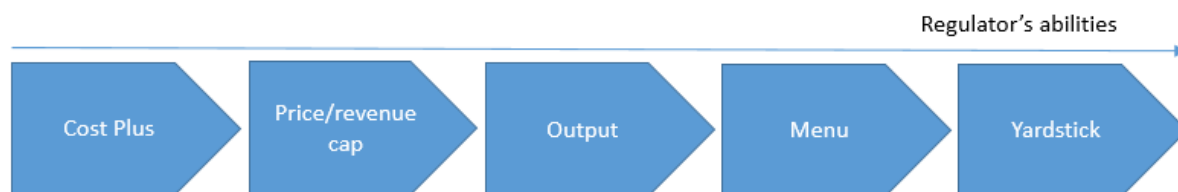


Figure 34: Illustration of incentive regulation tools in terms of the level of resources required by the regulator.

A task can be controllable if the network operator can largely control and enhance the efficiency of the targeted task. This may either be attained by increasing the level of output for the same input or by reducing the input required for the given output level. If the firm is unable to control the efficiency level of the task, incentive regulation would be ineffective as the efficiency level cannot be predicted. In this scenario, a cost-plus approach would be considered as a preferred alternative. On the other hand, if the task is controllable, incentive regulation can be utilised for regulating such tasks.

The second fundamental regulatory characteristic of the task is predictability, i.e. the ability to foresee the outcome of the task. If the task is controllable and has a high degree of predictability, a complex incentive mechanism could be implemented, provided that the regulator has a sufficient level of expertise. On the other hand, if the predictability of the task is low, a cost-plus approach could be applied.

A task can be considered observable if the impact of the effort by the network operator can be reasonably observed ex-post by the regulator and the network operator. However, it is important to implement credible key performance indicators within the network operation process to ensure effective monitoring. The degree of observability of a task may vary from historical data sets of a single firm to data from several comparable firms. If the level of observability is high and the regulator has relevant expertise, it may choose to implement an advanced regulatory tool such as menu contracts or yard-stick competition. If the resources of the regulator are limited, the choice of a cost-plus scheme may be the desirable regulatory framework.

The current practice in Europe is to apply price cap or revenue cap regulation (20 countries) to the TSO expenses to perform its tasks. Several countries (15) apply cost-plus (or rate-of-return) regulation, sometimes using a combination with price cap for opex and cost-plus for capex. Output-based regulation is applied in a few instances, but in Great-Britain and Italy, and recently in Belgium, the regulatory frameworks for the transmission level have some elements to reward performance based on output proxies (See Table 6).

7.2.2.3 ALIGNMENT OF REGULATORY TOOLS WITH THE RESOURCES OF THE REGULATOR

Glachant et al. (2013) observe that '[t]he practice of regulation is significantly different from its theoretical frame. Notably, the textbook model of regulators is always assuming that they have all the required abilities to design and implement the theoretically most efficient regulatory regime. However, in practice, lowly or badly endowed regulators may not be inclined or able to apply the most complex or most innovative regulatory tools to the network operators under their jurisdiction. In this section, the interdependence of the regulatory tools and the resources of the regulations are discussed in greater detail.

The economic literature that conceived regulatory tools generally assumed that regulators have all the necessary skills to choose and administer the most efficient regulatory tool. However, in practice regulators may face limitations in their abilities and make decisions in the realm of bounded rationality. Thus, the regulator may not have the necessary cognitive, computational and administrative abilities required to implement the desired regulatory tool effectively. Therefore, the regulator’s resources in terms of budget, skills and powers may limit the level of sophistication of the regulatory tool it may implement. Let us consider the alignment of cost-plus, price/revenue cap and output regulation from the perspective of the regulator’s resource requirement (Illustrated in Figure 6).

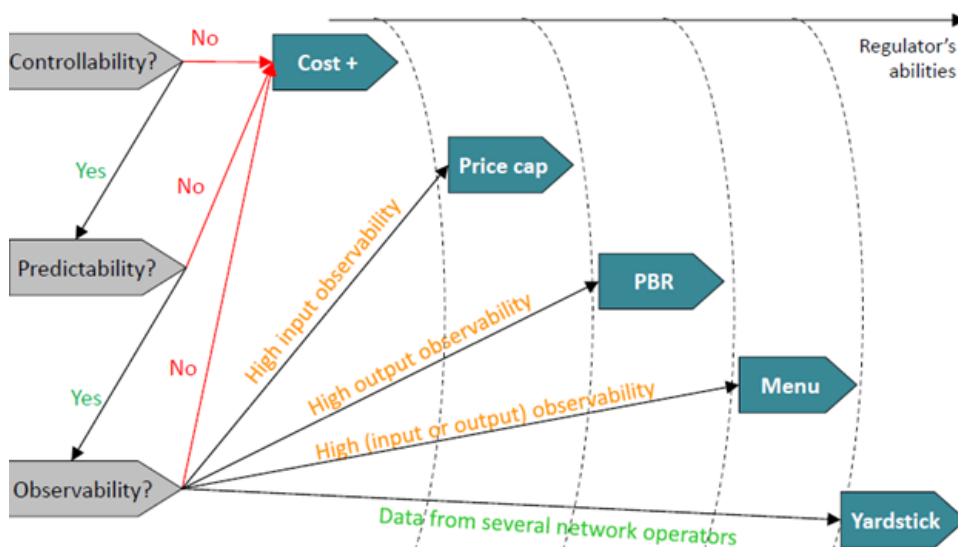


Figure 35: Decision tree to align tasks, regulatory tools and regulator’s abilities. Based on: Glachant et al. (2013)

Cost-plus regulation due to its low level of regulatory complexity would require the auditing of the TSOs books ex-post and the ability to justify it in a court if required. Eventually, the regulator would set the tariff based on the audited costs.

Price/revenue cap regulation is a forward-looking regulation that entails forecasting expected trajectory of efficient cost over the entire regulatory period. There exists a possibility that errors may arise if an unexpected change occurs in any of the factors used in calculating the ‘allowed revenue’. Thus, such an approach makes setting the correct efficiency factor and reference price complex task. Consequently, a higher level of skill is required.

Output regulation is even more complicated than the price/revenue cap and cost-plus approaches. Such regulation requires that the regulator defines a performance target explicitly for a given output along with a financial incentive for attaining this target. According to Glachant et al. (2013) ‘[t]his would necessitate from the regulator a definition of how the network operator already produces the various outputs and how it should be done better. It should also weigh the gains that any improvement of these outputs may have for the society as a whole vis-à-vis the value left to the operator in the financial incentive. Only under these conditions might the network

operator be able to make an efficient arbitrage between the costs and the benefits that an operational effort for output performance will generate for the society.’ Thus, due to the higher level of complexity, the regulator would also require a higher level of resources and skills for administering such a mechanism.

To successfully implement a menu contract, an even a higher level of regulatory expertise would be required in terms of the regulator’s abilities as compared output regulation. The regulator is required to design low-power and high power incentive schemes that cater to different firms with varying efficiency improvement profiles.

Yardstick competition can be considered as the most complex tool in terms of the regulatory expertise required to implement it. The effective implementation of yardstick competition is based on several assumptions. Firstly, a set of regulated firms functioning under similar conditions and performing similar tasks is required. Secondly, the regulator needs to collect, process and compare relevant data from the regulated firm using advanced statistical techniques that require time, budget and high skill level (Rious and Rossetto, 2018).

The assessment presented in ACER (2016) based on a survey of NRAs provides insight into the current resources of the regulators across Europe. Significant heterogeneity between member states is observed. While some NRAs have less than 12 full-time equivalent staff units (FTEs), others, such as Great Britain, have more than 220 FTEs.

No clear correlation between the FTE and the sophistication and complexity of the incentive regulation practice is observed. The larger NRAs do go beyond cost-plus, but the same is observed with some of the smaller NRAs, such as Estonia where a price/revenue cap approach is used. Relatively smaller NRAs do not apply output regulation, except for Belgium, which is classified as a small-mid size NRA. One of the reasons that a clear correlation is not observed is that the FTE is a weak proxy for resources available for the NRA to regulate a TSO. Some NRAs can focus their resources on the regulation of the TSO while others have a broader set of activities to perform. For instance, in Belgium, CREG is not responsible for regulating the DSOs. This is also observed by Rious and Rossetto (2018): ‘these numbers must be interpreted with caution, as they inevitably reflect the differences in size and structure of the national markets, the duty to regulate only electricity or natural gas too, and possibly the additional tasks and powers introduced at the national level.’

7.2.3 WHAT ARE WE INCENTIVIZING? TYPES OF TRANSMISSION ASSET INVESTMENTS

In this section, we discuss the types of transmission asset investment. Transmission investment has been a very stable activity for many decades. The main concern of utilities was to expand national grids to cope with demand increase and ensure the security of supply. However, as Europe tries to consolidate the internal market of electricity, the need for interconnection is becoming more relevant. European renewable targets may also impact transmission, as corridors may be required to carry this electricity to the load centres. ENTSO-E (2014c) indicates a significant rise in the share of new investments in the TYNDP project, (See Figure 36). An increasing part of investments come from the Ten-Year Network Development Plan (TYNDP), that include mainly cross-border investments.



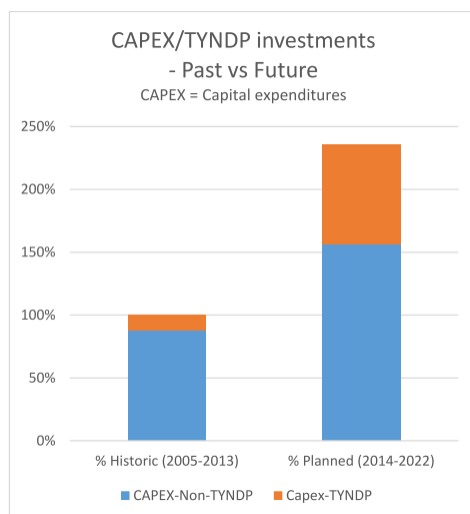


Figure 36: Transmission investment volumes in Europe Source (ENTSO-E 2014).

Investment in transmission assets can be broadly divided into three categories.

1) **Expansion of the grid:** It is composed of reinforcements made by TSOs to adapt the network to new demand profiles and replace old assets. The transmission expansion planning (TEP) is usually done using optimization tools by entities at the national level (Niharika et al., 2016).

2) **The connection of user to the grid.** This type of investment is different from the TEP, foremost, because these connections are demanded by the user and not centrally planned by the system operator. Usually, the causality of the cost in these cases is easily recognizable. Therefore, this cost can be easily allocated to the user demanding such connection. As explained in chapter 6, this cost allocation is executed using either a deep, shallow or super-shallow approach.

3) **Cross-border interconnectors.** Such investments are usually conceived in a bilateral negotiation or at a regional level due to the trans-national nature of such investments.

Investments in meshed offshore grids may differ from previous projects. For example, projects may be multi-jurisdictional, i.e., a project may be developed not in one or two countries, but in several countries. This adds complexity and changes the planning and permitting process, as several agents must be satisfied with the benefits and the sharing of costs. The investment decision for these projects will come from a regional discussion.

7.2.4 TYPES OF RISKS

The TEN-E Regulation, when referring to investment incentives for PCIs⁸⁰ in article 13, states that “ACER shall facilitate the sharing of good practices and make recommendations” regarding dedicated incentives and benchmark of best practice by national regulatory authorities, and regarding “a common methodology to evaluate the incurred higher risks of investments in electricity and gas infrastructure projects”. In this section, we discuss the risk assessment framework developed by ACER in the Recommendation 03/2014 (ACER, 2014b).

⁸⁰ Projects of Common Interest (PCIs) are infrastructure projects with a pan-European impact identified by the EC as essential for completing the internal energy market.

The methodology for risk evaluation developed by ACER is composed of five categories. According to the agency, “all project risks can, in general, be subsumed under five categories of risk from the perspective of the project promoter”. The five categories are:

1. **The risk of cost overruns:** The risk that the costs of a project turn out to be higher than expected
2. **The risk of time overruns:** The risk that development and construction of a project takes longer than anticipated
3. **The risk of stranded assets compensated:** The risk that there is no demand for the service the project offers after construction
4. **Risks related to the identification of efficiently incurred costs:** The risk that costs are not considered as being efficiently incurred by the regulator
5. **Liquidity risk:** The risk of not being able to meet financial commitments

For each of the above-mentioned categories, we present possible issues that may impact the risks for offshore meshed grids⁸¹. In the below paragraph we attempt to highlight the uniqueness of the offshore meshed grid approach in context, without delving into the debate on whether investment in meshed grids constitutes a higher risk and if so, then to what extent.

The major impact on the “**risk of cost overruns**” appears to arise from technology uncertainty. The meshed offshore network is expected to be developed in HVDC technology. It is well known that many components and operational procedures are still being developed. Therefore, the possibility of cost-overruns and time-overruns cannot be ruled out. Furthermore, the **risk of time overruns** may also be impacted by the multijurisdictional environment in which meshed offshore grids will be developed. Although European regulation pushes for a “one-stop shop” permitting process for PCIs, more countries will be involved in meshed solutions, and procedural inefficiencies may lead to time overruns. In the context of **stranded asset risks**, it is important to note that such assets deployed in the meshed offshore grid cannot be redeployed. Thus they may be considered to have a high asset specificity (Williamson (1988)). Consequently, investment interdependence between project promoters (as is the case with interconnectors) may have an impact on stranded asset risks. In a meshed offshore grid, several project developers may be involved. The withdrawal of any party for any reason post start of development may lead to the creation of stranded assets. Another possible impact is highlighted by Offshore Grid is that if the grid is developed, but some of the expected OWFs are not, a portion of the grid will be stranded. We do not observe any unique characteristic in meshed offshore grids that may impact **liquidity risk**. Finally, we do not comment on **risks related to the identification of efficiently incurred costs** as it appears outside the scope in the current level of development of the meshed offshore grid.

⁸¹ A quantitative analysis of the impact of these factors on actual change in risk level needs to be conducted in the future to understand the magnitude of impact and conclusively comment on the difference in risk between offshore and terrestrial network investments. However, it is outside the scope of this research.

7.3 ANALYTICAL FRAMEWORKS

In this section, we explain the frameworks used to assess the level of incentive provided in the national regulatory frameworks of the countries under consideration. This analysis is divided into two parts. In the first one, the default national regulatory frameworks are analysed. In the second, “dedicated incentives” for investments in these countries will be evaluated.

7.3.1 DEFAULT NATIONAL REGULATORY FRAMEWORKS

As shown by Meeus and Keyaerts (2014), a default national regulatory framework is usually applied to remunerate all transmission projects, independent of their characteristics and risk profiles. This is a common practice since most regulatory regimes treat investments on a portfolio basis. In general, when the TSO makes an investment, the new asset is included in the regulatory asset base (RAB), and the RAB is remunerated according to a weighted average cost of capital (WACC), composed by the cost of debt (CoD) and return on equity (RoE).

$$WACC = \frac{Debt}{Debt + Equity} * CoD + \frac{Equity}{Debt + Equity} * RoE$$

The CoD is the cost of external capital while the RoE is the return on the shareholder's capital. To calculate the RoE, regulators usually rely on the capital asset pricing model (CAPM) (I. J. Pérez-Arriaga, 2013):

$$RoE = Rf + \beta * (Rm - Rf)$$

Where,

Rf is the risk-free rate of interest,

Rm is the expected return on an efficient market portfolio, and

β is the volatility of the value of the company's financial assets (shares) compared to average market volatility.

By analyzing both the WACC and CAPM models, one can easily see that no project is considered individually, but in a portfolio fashion. In fact, ACER (2014) notes that:

“This very common risk evaluation approach focuses on the identification of the level of systematic risk for the overall transmission activity through the “beta” coefficient, which is usually included in the formula for the weighted average cost of capital (WACC).” (pg. 3)

While the systematic risk is expected to be considered by the CAPM model, project-specific risks are not. These are to be balanced through the portfolio effect, meaning that one project's loss is supposed to be compensated by other project's gain.

Therefore, considering the portfolio-based characteristic of default national regulatory frameworks, in the first part of the analysis, the incentive provided by these default frameworks is analyzed. We use an analytical framework based on the one developed by Glachant et al. (2013).

Glachant et al. (2013) provide an in-depth analysis of incentives for investments by European TSOs. The report recognizes the large volume of investments needed in transmission assets in the coming years and discusses whether national regulatory regimes can cope with the need for investment. National regulatory regimes are analyzed based on four main economic aspects of regulatory regimes. They are defined as the capability to:

1. Sufficiently remunerate TSO investments and to ensure their financeability.
2. Reduce the risk born by the TSO.
3. Incentivise TSO cost reduction.
4. Transfer efficiency gains and redistribution to final users.

To analyze if these economic aspects hold on regulatory regimes, five main characteristics are investigated for each country.

1. The length of the regulatory period
2. The scope of the revenue cap (TOTEX versus building blocks)
3. The tools to define allowances and efficiency targets (benchmarking versus cost and efficiency audit)
4. The practical setting of the capital remuneration
5. The adjustment mechanisms

Regulators set these characteristics to have a direct impact on the economic properties of the regulatory regime. For instance, the scope of the revenue cap will have a direct influence on the capability to reduce the risk borne by the TSO and to incentivize cost reduction. On the one hand, if the revenue cap is applied to TOTEX⁸², there is a higher risk for the TSO and a high incentive for total cost reduction. On the other hand, if the revenue cap is applied only on controllable OPEX, there is reduction of risk for the TSO (as the TSO will not bear the risk for CAPEX and non-controllable OPEX) and the incentives for cost reduction are also limited (no incentive for cost reduction on investment, for instance). The same reasoning applies to every characteristic and every economic aspect.

The research report defines two extreme regulatory regimes. The first one is the "risk of gold plating zone", in which TSOs have a very high remuneration and bear a very low risk. In this region, TSOs have very high incentives to invest, and possibly they will over-invest. The other extreme is the zone called "risk of underinvestment". This hypothetical regime is characterized by high incentives for cost reduction and low remuneration.

⁸² TOTEX stands for total expenditures. It includes the CAPEX, or capital expenditures, and the OPEX, or operational expenditures.

The study carries an analysis of five different countries using the framework described above. The selected countries are Belgium (the regulatory period from 2012 to 2015), France (the regulatory period from 2013 to 2016), Germany (the regulatory period from 2014 to 2018), Great Britain (the regulatory period from 2013 to 2021) and the Netherlands (the regulatory period from 2014 to 2016). The report concludes that a misalignment among regulatory regimes exists and that harmonization is desirable if the needed European investment is to be made.

The methodology used here is based on the report by Glachant et al. (2013) and encompasses a discussion of the five aforementioned characteristics. The configurations of these characteristics would impact on the level of risk as well as remuneration for the regulated company.

The length of the regulatory period, for instance, increases the risk for the regulated company as it gets longer. In general, a long regulatory period gives a higher incentive for cost reduction, as the shorter the regulatory period gets, the closer it is to a cost-plus regulation. Also, a longer regulatory period incorporates more uncertainties, as the ex-ante assumptions will impact the utility for a longer period. A long regulatory period also increases the regulatory risk, as the regulator may be tempted to review the revenue cap during the regulatory period (Glachant et al., 2013).

The scope of the revenue cap is also an important instrument of risk allocation. Considering one extreme, the revenue cap can be based on the TOTEX of the regulated company. Thus, the company has incentives to reduce costs on the operations but also on the investments. With these configurations, the regulator considerably increases the risk for the TSO. On another extreme, the revenue cap can be applied only on the so-called "controllable OPEX", meaning that both CAPEX and the part of the OPEX that the company has less control over are treated as pass-through items. The risks, in this case, are transferred from the TSO to the grid users. In between these two extremes, other forms of "building block" approaches are possible, allocating more or less risk to the utilities.

The tools to define the revenue caps can also impact on the risk born by the TSO. Three main tools are used for this purpose. The first and maybe more common is the efficiency audit, and it is based on the detailed analysis of the costs of the TSO. The moment of this detail analysis matters. An ex-post efficiency audit introduces risk for the TSO and therefore can be combined with ex-ante evaluation of investments (Glachant et al., 2013). Another way of setting the revenue cap is through a menu of contracts. In this method, the regulator offers to the TSO several possible levels of risks with differently allowed revenues. The third method of revenue cap setting is through benchmarking, also called yardstick. This method usually tries to set an efficiency frontier from a sample of companies. For this method, the critical feature is the comparability between the sample and the regulated company (Glachant et al., 2013).

The fourth characteristic to be analyzed is the **setting of remuneration** itself and the tools to set it. As already mentioned, most regulatory regimes define a WACC for the TSO. Within the WACC, the treatment of the CoD may vary. The regulator can accept the real CoD or estimated it. The gearing (ratio between debt and equity) is

also an important measure. If not properly set, it will increase or decrease the remuneration for the TSO. The RoE may also vary considerably, and in it is the expected return for the TSO over the services they provide.

Finally, we also analyse whether the default regulatory mechanisms also provide **adjustment mechanisms**, usually to correct distortions created by ex-ante assumptions. One example is the volume adjustment. The OPEX estimation, and consequently the revenue cap, take into consideration an assumption of future demand. If the assumption proves to be wrong, regulators can adjust the revenues accordingly ex-post. In fact, the adjustment can be used not only to ex-ante assumptions but also to other exogenous factors that may impact the TSO's outcome.

After analysing each of the five characteristics of the five selected countries, we plot, in a stylized and illustrative way, the relative position of the default national regulatory frameworks according to risk and reward, as proposed in Figure 37 . The plot is based on the work by Glachant et al. (2013) and shows four diagonal regions. The left upper corner is the "risk of under-investment" area, in which TSOs bear very high risk and have a low remuneration. The mid-upper diagonal section represents a situation in which the TSO has elevated risks and not so high remuneration. In these regions of the plot, TSOs are incentivized to reduce costs in the short term, and therefore consumption of electricity is expected to be higher as the tariffs reduce (Glachant et al., 2013). The mid-lower section represents the situation in which TSOs have a high remuneration in proportion to the risks borne. This situation is expected to incentivize investments, bring cost reduction in the long term and short-term benefits for shareholders (Glachant et al., 2013). Lastly, the bottom-right corner is the "risk of gold plating" region that should be avoided by regulation, as TSOs would be incentivized to over-invest.

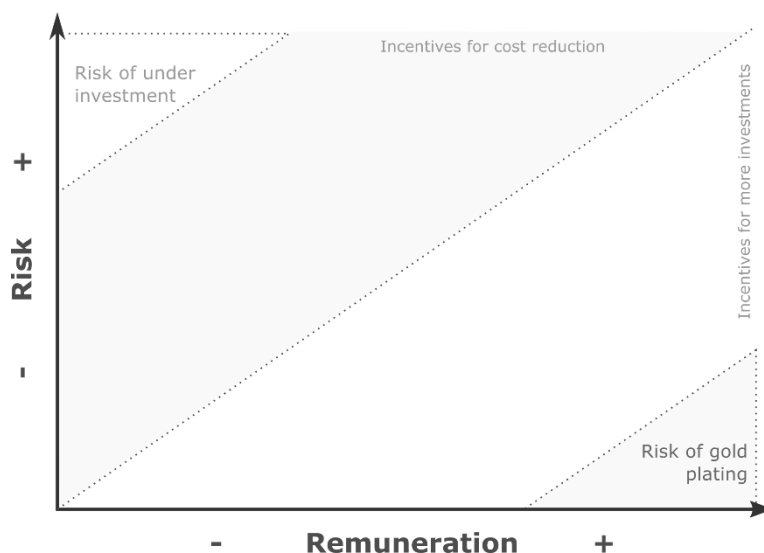


Figure 37: Stylized plot of Economic Incentives provided by Default National Regulatory Regimes

7.3.2 DEDICATED INCENTIVES

Glachant et al. (2013) provide one approach when analysing the capacity of the national regulatory regimes in providing efficient economic incentives for investments. The analysis focus on the general regulatory framework, and therefore apply to all investments.

However, there is an alternative direction for dealing with specific investments for TSOs is by the implementation of dedicated incentives. In fact, this approach is already mandated by the TEN-E Regulation for PCIs. Article 13(1) states that

“Where a project promoter incurs higher risks for the development, construction, operation or maintenance of a project of common interest falling under the categories set out in Annex II.1(a), (b) and (d) and Annex II.2, compared to the risks normally incurred by a comparable infrastructure project, Member States and national regulatory authorities shall ensure that appropriate incentives are granted to that project in accordance with Article 37(8) of Directive 2009/72/EC, Article 41(8) of Directive 2009/73/EC, Article 14 of Regulation (EC) No 714/2009, and Article 13 of Regulation (EC) No 715/2009.”

Keyaerts and Meeus (2017) explore how dedicated incentives can be set, and analyse of the mechanisms used in Italy and the United States⁸³. The authors discuss the approach of using dedicated incentives as follows

“Glachant et al. (2013)⁸⁴ argue that in the tradeoff between the investment risk and the remuneration of the transmission firm, the national regulatory framework should ensure that the remuneration is sufficient for all investment, including the investment that is subject to greater cost uncertainty. This approach is fine to the extent that the necessary investment is comparable to regular investment. However, it could be less costly to offer dedicated incentives only to the strategically important investment, on a case-by-case basis, whereas regular investment remains subject to standard regulatory treatment. These dedicated incentives comprise customization of one or more of the main regulatory parameters, which are the length of the regulatory period, the return on equity, the specified efficiency targets, and the scope of the revenue cap.”

Thus, in other words, these incentives are supposed to go on top of the default national regulatory framework. They can lead to a higher remuneration on the specific investment, thus mitigating risks for the project developer. According to Meeus and Keyaerts (2014), the remuneration increase is mainly done in two ways, namely a fixed premium for an eligible project or through a case-by-case assessment and individual premium. The risk mitigation is done by exemption from the default CAPEX efficiency benchmarking, increasing the regulatory period, advance timing of development cost recognition or advance timing of construction cost recognition. Associated with the

⁸³ According to the authors, Italy applies a fixed additional remuneration if the project is considered strategic and meets some requirements, while in the US a detailed case-by-case analysis is conducted that may lead to additional remuneration and risk mitigation measures.

⁸⁴ The authors refer to (Glachant et al., 2013)

dedicated incentive, usually, an ex-ante assessment of eligibility is also implemented in order to control the cost efficiency of the investments that eventually will receive the dedicated incentive.

The motivation behind the implementation of such mechanisms can vary. Firstly, we note that European regulation already mandates the existence of dedicated incentives for PCIs, following the TEN-E Regulation, as presented earlier. However, some countries go beyond that legal requirement, implementing mechanisms that are not limited to PCIs only. Meeus and Keyaerts (2014) show that

“At first sight, the dedicated frameworks seem to be motivated by temporary exceptional challenges. Countries refer to promoting competition, electricity market integration or prioritizing strategically important or socially desirable investment at national level. They argue that to meet their challenges, it is necessary to temporarily speed up the needed “exceptional investments”. (p. 2)

7.4 CASE STUDIES

7.4.1 DEFAULT REGULATORY FRAMEWORKS

In this section, default regulatory frameworks in the four countries under consideration are discussed and analysed based on the framework discussed in Section 7.3.1.

7.4.1.1 GREAT BRITAIN

In Great Britain, the Office of Gas and Electricity Markets (Ofgem) is the National Regulatory Authority and therefore regulates the TSOs in England, Scotland and Wales. There are four of these: National Grid Electricity Transmission (NGET), responsible for England and Wales, Scottish Hydro-Electric Transmission Limited (SHET), responsible for the North of Scotland, and Scottish Power Transmission Limited (SPT), responsible for the South of Scotland (Ofgem, 2017a)⁸⁵.

Great Britain was a pioneer in the implementation of incentive regulation in the early '90s with the RPI-X system (Nixon et al., 2009). The RPI-X is still one of the main regulatory regimes for incentive regulation. In this regime, the regulator establishes ex-ante the yearly allowed revenue for the upcoming regulatory period. The regulated company will receive that revenue adjusted for the inflation (RPI) and an efficiency index X. This efficiency index is an incentive for the company to reduce costs. If the company does not reach such cost reductions, they will operate at a loss, while if they can reduce expenses in a higher ratio than the X factor, the company can account for the extra money as profit.

However, in 2010, Ofgem announced a profound change in the regulatory regime. The new framework in place since 2013 is called RIIO, standing for “Revenue = Innovation + Incentives + Output”. It shifts from the idea of regulating inputs to regulating outputs. Regulated companies should provide outputs to their customers at the

⁸⁵ Note that we analyze Great Britain and not the United Kingdom as a whole. That is because in Northern Ireland, another regulatory regime is in place, set by the Northern Ireland Authority for Utility Regulation (the Utility Regulator), different from the one set by Ofgem in Great Britain.

minimum cost. These outputs are divided into six categories: customer satisfaction, reliability and availability, safety, conditions for connection, environmental impact, and social obligation (Ofgem, 2010). Utilities should elaborate a business plan at the beginning of the regulatory period stating how they plan to achieve such outputs. This business plan is evaluated by Ofgem and serves as a reference when setting the allowed revenues. Although this report focuses on the existing RIIO regime, it should be noted that from 2021, Great Britain will move to an updated price control regime known as RIIO-2.

LENGTH OF THE REGULATORY PERIOD

The regulatory period in the UK lasts for eight years. In fact, it is still the first regulatory period for the RIIO framework (referred to as RIIO-T1 for the transmission companies (Ofgem, 2013a)). It started in 2013 and will finish in 2020. In the middle of the regulatory period, a mid-period review is expected to happen. This review was just completed for the first period for National Grid. As a result, Ofgem reduced National Grid’s spending allowances by £185 million (Ofgem, 2017b), adjusting the required revenues accordingly to the reduction of necessary investments. According to OFGEM, (2018), the regulatory period for RIIO-2 will be 5 years.

SCOPE OF THE REVENUE CAP

The revenue cap follows a TOTEX approach in GB, meaning that both OPEX and CAPEX are subject to a cap established by Ofgem. The TOTEX revenues are divided into two types, namely fast money and slow money. The former is a percentage of the TOTEX that the utility can recover in one year. The rest of the TOTEX, called slow money, is included in the Regulatory Asset Value (RAV), is depreciated and remunerated according to a WACC (National Grid, 2016).

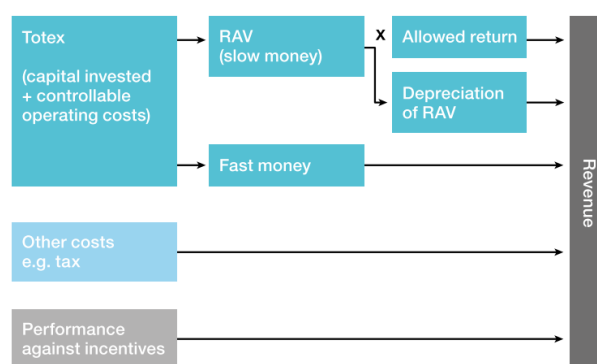


Figure 38 RIIO regulatory building blocks SOURCE: (National Grid, 2016)

According to OFGEM, (2018)0, In the context of RIIO-2 “existing depreciation policy of using economic asset lives as the basis for depreciating the RAV” will be maintained.

DEFINITION OF EFFICIENCY TARGETS

The RIIO framework is a combination of output incentives and cost efficiency incentives. For the cost efficiency incentives, a menu of contracts is used (Glachant et al., 2013). The mechanism is called Information Quality

Incentives (IQI). This mechanism aims to give an incentive for companies to declare their real costs when submitting their business plans, as they will be rewarded (or penalized) according to the real cost incurred at the end of the period. This also functions as a way of sharing efficiency gains with the final consumers. According to OFGEM, (2018), for RIIO-2, OFGEM “*will develop alternative incentives for business plans, including the role of IQI, as part of the work on sector specific methodologies.*”

SETTING OF THE CAPITAL REMUNERATION

RIIO bases its remuneration on a WACC calculated by Ofgem. According to Ofgem (2010):

“The allowed return has two main roles in the regulatory framework. First, it provides a fair return to existing investors in network companies and second it is the value which facilitates investment in new infrastructure. Under the RIIO model, we will continue to set an allowed return on the basis of a single weighted average cost of capital (WACC).” (p. 108)

The cost of debt is indexed to the 10 years moving average of the pound sterling Non-Financials A and BBB 10+ year's indices published by iBoxx (Glachant et al., 2013), 2.38% for 2016/17 (National Grid, 2016). For the cost of equity, the CAPM is used (Ofgem, 2010). According to National Grid's annual report, their cost of equity was defined at 7% and the gearing at 60%. For the other companies, the gearing ranges from 55 to 60% (CEER, 2016).

Table 22: National Grid's cost of capacity allowed under RIIO SOURCE: (National Grid 2016)

	Transmission		Gas Distribution ²
	Gas	Electricity	
Cost of equity (post-tax real)	6.8%	7.0%	6.7%
Cost of debt (pre-tax real)	iBoxx 10-year simple trailing average index (2.38% for 2016/17)		
Notional gearing	62.5%	60.0%	65.0%
Vanilla WACC ¹	4.03%	4.22%	3.89%

According to OFGEM, (2018), for RIIO-2, the CAPM approach will be applied to estimate the cost of equity. The calculation of CAPM will be cross-checked against “*Market to Asset ratios (MAR) and returns bid by investors (e.g. against OFTOs).*”

ADJUSTMENTS

Although the long regulatory period, the framework has a mid-period for adjustments. Also, two reopeners in May 2015 and May 2018 were possible for the TSO to require additional revenues (Glachant et al., 2013). The TSO is also hedged against volume risk under the RIIO regulation (Glachant et al., 2013). According to OFGEM, (2018), the regulatory period for RIIO-2 will be 5 years.

7.4.1.2 GERMANY

Transmission activity in Germany is performed by four different companies, namely TenneT, 50Hertz, AMPRION, TransnetBW. The regulator responsible for setting the framework for the four companies is the BNetzA.

Incentive regulation was introduced in 2009. For transmission businesses, the regulatory period is five years, and currently, the second regulatory period is in place. Not much has changed from the first to the second regulatory period, except for the regulatory parameters (Glachant et al., 2013)⁸⁶.

LENGTH OF THE REGULATORY PERIOD

The regulatory period in Germany is 5 years (CEER, 2016).

SCOPE OF THE REVENUE CAP

A TOTEX approach is used to set the revenues cap, but not all the costs are included. The base level cost is composed by permanently non-controllable costs and generally controllable costs (Bundesnetzagentur, 2017). The efficiency level is applied to the generally controllable costs to create what is called a block of efficient, controllable cost. The TSO should then reduce the remaining part, the inefficient block, over the course of the regulatory period.

DEFINITION OF EFFICIENCY TARGETS

To define the efficiency levels, the German regulator uses a benchmarking technique. Gas, distribution, and transmission are treated separately. For transmission, the procedure considers not only the four TSOs in Germany but an international sample including TSOs from other EU Member States (Bundesnetzagentur, 2017).

SETTING OF THE CAPITAL REMUNERATION

Germany also uses a WACC methodology for the remuneration and the CAPM model to compute the RoE (Glachant et al., 2013). For the five year regulatory period starting 2019, the RoE for new facilities is set at 6.91% and for old facilities at 5.12%.

ADJUSTMENTS

Volumes are also offset by the regulatory framework in Germany. At the end of the fifth year of the regulatory period, the difference is calculated and taken into consideration when calculating the revenue cap or the following period.

⁸⁶ For details on main incentive regulation tools in Germany please see: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/GeneralInformationOnEnergyRegulation/IncentiveRegulation/Tools/IncentReg_Tools-node.html

7.4.1.3 DENMARK

The Danish TSO Energinet.dk is regulated by the Danish Energy Regulatory Authority (DERA). Energinet.dk was created in 2009, following the unbundling requirements of the Third Package (Lockwood, 2015). Nevertheless, the company is wholly state-owned and is not allowed to build equity or share profits with its owner, the Danish Ministry of Energy, Utilities and Climate (Danish Energy Regulatory Authority, 2015).

Therefore, Energinet.dk is under a strict cost-plus regulatory framework, designed to recover only the "necessary costs" for efficient operation and a "necessary cost of capital" (Danish Energy Regulatory Authority, 2015). The cost of capital, however, refers to the CoD only, as no RoE is included. Any surplus collected by the TSO must be transferred back to the consumers, and similarly, any deficit will be offset by the tariff.

LENGTH OF THE REGULATORY PERIOD

No regulatory period is applied in Denmark, as it is under a cost-plus regulation. Costs are scrutinized annually by DERA.

SCOPE OF THE REVENUE CAP

Also not applicable to cost-plus regulation. In fact, not even the concept of cost-plus is the most appropriate, as the "plus" is missing. The regulatory framework aims to recover only the cost incurred by the TSO.

DEFINITION OF EFFICIENCY TARGETS

Annual scrutiny is carried by DERA to determine the allowed costs to be recovered. According to the Danish Energy Regulatory Authority (2015), Energinet.dk participated in two European benchmarks of TSOs, and that these benchmarks are important for "DERA's economic regulation and assessment of Energinet.dk". It is important to note that, according to CEER (2016), "the regulation does not facilitate the determination of general efficiency requirements for Energinet.dk. However, DERA may determine that a specific cost - or the amount thereof - does not constitute a necessary cost at efficient operation and therefore may not be included (or only partially included) in Energinet.dk's tariffs".

SETTING OF THE CAPITAL REMUNERATION

As mentioned before, Energinet.dk is not entitled to a RoE. Instead, there is only an interest rate to ensure the real value of the company's capital base as of 1 January 2005 (CEER, 2016).

ADJUSTMENTS

According to the Danish Energy Regulatory Authority (2015), differences in the real efficient cost incurred and the revenues corrected by the tariff can be offset in the following year.



7.4.1.4 THE NETHERLANDS

The Dutch TSO TenneT was appointed as the independent operator at the beginning of the liberalization of the electricity sector in The Netherlands (Glachant et al., 2013). TenneT is regulated by the Authority for Consumers and Markets (ACM). They are currently entering the 7th regulatory period, starting in 2017 and finishing in 2021. The regulatory regime in The Netherlands can be summarized as a TOTEX revenue cap with the application of an RPI-X formula for the remuneration of transmission services (Glachant et al., 2013).

LENGTH OF THE REGULATORY PERIOD

The regulatory periods range from 3 to 5 years. The current regulatory period was set to 5 years, instead of the 3 of the previous period (2014-2016).

SCOPE OF THE REVENUE CAP

The revenue cap is based on the TOTEX (OPEX, new and old investment in the RAB) (Glachant et al., 2013).

DEFINITION OF EFFICIENCY TARGETS

The revenue cap and efficiency targets are calculated two years prior to the beginning of the new regulatory period. The regulator looks at the incurred costs by the regulated company and uses it as a baseline for the upcoming period. The efficiency targets are then defined (the X factor). For that purpose, two analyses are used. The first is a benchmark to define an "efficient cost reference", while the second is an expected productivity improvement due to technological advancements (Glachant et al., 2013).

SETTING OF THE CAPITAL REMUNERATION

The remuneration is computed using the WACC formula, considering a gearing of 50% (CEER, 2016). Different WACCs are used for new assets and for existing assets. The WACC for the new period will also decrease linearly until the end of the regulatory period. The real pre-tax WACC for existing assets was set at 4.3% and will decrease to 3.0% in 2021. For new assets, it will start at 3.6% and also finish at 3.0% (TenneT, 2017b). The RoE for The Netherlands we calculate at 3.54%⁸⁷.

ADJUSTMENTS

According to TenneT (2017), adjustments mechanisms previously in existence were excluded for the new regulatory period:

⁸⁷ RoE calculated based on the parameters presented by CEER (2016). The formula used was $RoE = Rf + \beta * Mp$, where Mp is the Market Premium, and is defined as $Mp = Rm - Rf$. The risk-free rate used is real, and therefore this computation provides a real post-tax RoE, ensuring comparability with the other countries.

“the ACM abolished the bonus malus system with capped risk for TenneT TSO NL for the procurement costs for grid losses, reactive power and congestion management for transport services. Instead, the ACM has incentivised limiting these costs by setting a fixed budget on the basis of historic costs and additionally applying a frontier shift on these costs; this effectively exposes TenneT TSO NL to full price and volume risk.” (pg. 7)

7.4.1.5 BELGIUM

Regulated by the CREG (an acronym for Commission for Electricity and Gas Regulation in Dutch and French), Elia System Operator is the only TSO in Belgium. The company is partially owned by municipalities and partially owned by common shareholders as the company is listed on Euronext⁸⁸. The company also owns 60% of 50Hertz, one of the TSOs operating in Germany. The regulatory framework applied can be defined as a revenue cap based on a “building block” approach with incentive mechanisms for cost reduction.

LENGTH OF THE REGULATORY PERIOD

The regulatory periods are set for four years. The current regulatory period started in 2016 and finishes in 2019. It is the third regulatory period in Belgium (Elia, 2017b).

SCOPE OF THE REVENUE CAP

The revenue cap is applied to “building blocks”, meaning that part of the expenditures is subject to incentive regulation, and a part is passed through to the consumer. Costs are divided mainly into two categories, namely non-controllable elements and controllable elements. The former include depreciation of tangible fixed assets, ancillary services⁸⁹, costs related to line relocation imposed by a public authority, and taxes (Elia, 2017b). These costs are not subject to efficiency targets. The controllable elements are the costs over which Elia has control, and therefore are subject to efficiency measures. The efficiency gains are shared with the consumers. If incurred costs are lower than the allowed budget, 50% of the gains are accounted as profit for Elia. On the contrary, any overspending is a loss for the company (Elia, 2017b).

DEFINITION OF EFFICIENCY TARGETS

The efficiency target (X-factor) is determined based on benchmarking and dynamic productivity targets (Glachant et al., 2013). The benchmark aims to set an “efficient and comparable network” for comparison. The dynamic productivity targets (“frontier shift”) accounts for the increase in productivity due to technical advancements in the transmission business.

⁸⁸ European stock exchange seated in Amsterdam, Brussels, London, Lisbon and Paris.

⁸⁹ Except for the reservation costs of ancillary services excluding black start, which are called “Influenceable costs”.

SETTING OF THE CAPITAL REMUNERATION

Elia receives a so-called "fair remuneration on capital invested". This methodology is basically a WACC with an implicit gearing of 67%. Therefore, 33% of the RAB is remunerated according to the RoE formula (see formula 4.2), and the remaining 67% receive the risk-free rate (OLO, Belgium 10-year linear bonds) and an additional of 70 base points (Elia, 2017c). According to the current parameters provided by CEER (2016), the RoE is 2.74%⁹⁰. The low RoE is because of the recent decreased in the OLO. However, other dedicated incentives contribute to compensate for this effect, as shown by Elia (2017b):

"Despite the decrease in the yearly average OLO, from 0.86% in 2015 to 0.49% in 2016, the regulated net profit increased by € 8.5 million thanks to the full realisation of the mark-up investments plan and high efficiencies, which the consumers are also benefiting from."

ADJUSTMENTS

Both volume correction and a non-controllable costs settlement are applied ex-post.






7.4.1.6 SUMMARY AND INTERPRETATION

Table 23 shows a summary of the characteristics of the default national regulatory regimes in the five countries analysed. In front of every characteristic, an arrow shows the effect it has on remuneration or risk allocation. An arrow pointing up means higher risk is being allocated to the TSO (the country's flag will move up on the plot), and an arrow pointing down means a reduction in risk for the TSO. Similarly, an arrow pointing to the right means higher remuneration, and an arrow pointing left means lower remuneration.

Following the summary of characteristics, the plot is made comparing the level of economic incentive provided by each default national regulatory framework. The position of each country is illustrative, and although the axes of the graph represent scales, no inference about the actual amount can be made. It serves rather as a comparative illustration of the qualitative analysis.

⁹⁰ Calculated based on (CEER, 2016), following the same procedure as for the calculation of the RoE in The Netherlands.

Table 23: Summary of Default National Framework Characteristics⁹¹

					
Length of the Regulatory Period	↓ 4 years	↑ 5 years	↓ Yearly	↑ 8 years (with a mid-period review)	↑ 5 years
Scope of Revenue Cap	↓ Building blocks (non-controllable elements are pass through)	↑ TOTEX approach	↙ "Cost-plus" mechanism. TSO is not allowed to have profits.	↑ TOTEX approach	↑ TOTEX approach
Definition of Efficiency Targets	↑ Benchmarking ↑ Dynamic efficiency targets	↑ Benchmarking		↑ Outputs and cost efficiency goal ↓ Regulatory assessment of costs ↓ Menu of contracts (IQI) ↑ Benchmarking	↑ Benchmarking ↑ Dynamic efficiency targets
Capital Remuneration	← RoE 2,74% (Post-tax real, G=67%)	→ RoE 5,83% (Post-tax real, G=60%)		→ RoE 7,00% (Post-tax real, G=60%)	← RoE 3,54% (Post-tax real, G=50%) ← Decreasing WACC
Ex-post Adjustments	↓ Volume correction ↓ Non controllable costs settlement	↓ Volume Adjustment		↓ Mid-period review ↓ Volume adjustment	↑ Reduced hedging against price and Volume risk.

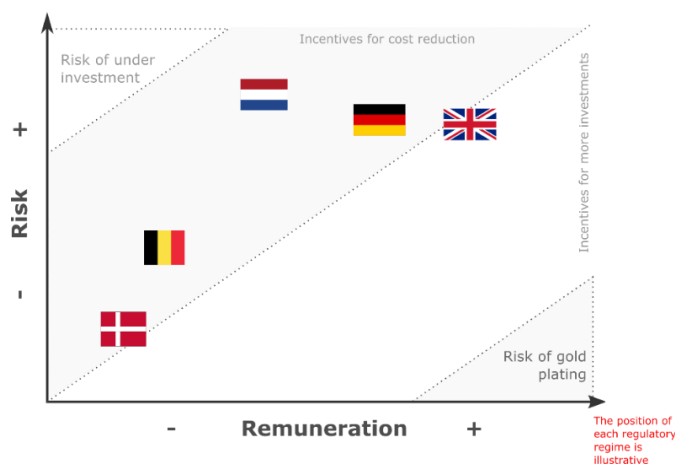


Figure 39: Plot of stylized economic incentives from default national regulatory frameworks

7.4.2 DEDICATED INCENTIVES

In this section, we analyse the dedicated incentive schemes in the remaining four countries, with the exception of Denmark, as the regulatory model applied to that country is in essence very different from the others. Attention is

⁹¹ Note for GB the existing RIIO mechanism is assessed.

paid to mechanisms that could be relevant in a meshed offshore grid context, namely the ones regarding offshore wind farm connections and the ones for interconnections (including offshore interconnectors).

7.4.2.1 GREAT BRITAIN

Dedicated incentives in Great Britain are not all concentrated in one package of measures. Although there is a main program called Strategic Wider Works (SWW), other policies and decisions also serve the purpose of dedicated incentives, as described below.

The regulator in Great Britain acknowledges the fact that a significant volume of investments will be needed within the current regulatory period, and that some projects may not have been included when setting the parameters for the upcoming period (Ofgem, 2013b). Therefore, the SWW scheme allows TSOs to bring projects forward once they are mature enough. Once the TSO presents the project for consideration under the SWW, Ofgem carries a project assessment to verify if the request is justified. If so, the project can be developed by the TSO, and outputs and allowed revenues are adjusted. However, another option is also being developed, as an onshore competition model is being proposed. The project will also be tendered and thus developed by competitively appointed transmission owners (CATOs) (Allen & Overy, 2016). For that tender, case-by-case incentives and risk allocation measures will be set. The legislation on this model is still being developed (Ofgem, 2017c).

Another dedicated framework for specific assets is the Offshore Transmission Owner (OFTO) model. This framework deals specifically with offshore connections. Since 2009, connections farm-to-shore are built not by the TSO, but by the developer, which transfers the ownership to a competitively appointed OFTO after completion (Ofgem, 2014a). Now Ofgem wants to go one step further and promote the "OFTO build" model, in which the construction of the connection will also be a responsibility of the OFTO. Ofgem (2014) explains the importance of the OFTO build framework:

"The extended OFTO build framework ensures OFTO build remains a viable and fit for purpose option with flexibility to respond to both the current and future requirements of offshore generators and to adapt to specific project characteristics." (p. 6)

Lastly, a separate regime may also be applied to interconnections. This was the case for the NEMO interconnector, a 1 GW subsea cable linking Belgium and the UK. For this infrastructure, a "cap and floor" regime was adopted, meaning that the project developer is allowed to receive revenues from the congestion of the interconnection, limited however to a floor, ensuring a minimal revenue for the developer, and a cap, avoiding the overpayment by users (Ofgem, 2014b).

To calculate the levels of the revenue cap and floor, Ofgem used a "building block". First, an assessment of efficient costs for the project was carried out, followed by a return on capital assessment and an OPEX assessment (Ofgem, 2014b).



It is interesting to note how Ofgem (2014b) defines the purpose of the cap and floor regime:

“The cap and floor regulatory regime sets a framework for GB interconnector investment. This developer-led approach balances incentivising investment through a market-based approach, with appropriate risks and rewards for the project developers.” (p. 5)

7.4.2.2 GERMANY

Germany has dedicated incentives schemes for cross-regional, cross-border and offshore investments (Meeus and Keyaerts, 2014). Thus, we focus on the offshore connections.

Germany was a leader in the deployment of offshore generation, as a part of their *Energiewende*⁹². The rapid growth in installed capacity, however, represented a challenge for the construction of the connections. In Germany, the TSOs are responsible for the connections and are indeed obliged by law to provide the OWFs with the access to the main grid. Before 2012, the TSOs were rather "reactive" and associated with several reasons; connections faced several delays (Schittekatte, 2016).

After 2013 the regime for offshore connections changed, leading TSOs to a more "proactive" posture. An Offshore Grid Development Plan (O-NEP) was made and updated yearly, and the completion date became binding for the TSOs. In 2017 another change in the framework came into place (TenneT, 2017b), as the Offshore Wind Act (Windenergie-auf-See-Gesetz) came into effect. The support scheme changed from the fixed feed-in premiums to auctions.

Although the connections are mandated by law for TSOs, some additional incentives are given in the form of risk mitigation. The offshore connections are usually approved by BNetzA under the so-called investment measures. Under this category, offshore connections are qualified as permanently non-influenceable costs to which no efficiency targets apply. Also, costs are directly included in the revenue cap based on planned costs (TenneT, 2017b).

7.4.2.3 THE NETHERLANDS

In the Netherlands, the TSO is also responsible for the connection farm-to-shore, and as in Germany, special risk mitigation measures apply.

On September 2016, the Dutch regulator ACM published, along with the other information on the new regulatory period, the rules for offshore grid investment from 2017-2021 (TenneT, 2017b). Offshore grid investments are remunerated while under construction, and no benchmark/theta or frontier shift will apply in this first regulatory period. The maximum depreciation period for offshore grid assets is 20 years. The WACC though is the same as

⁹² Energy transition, in German. Represents the process of moving towards a low-carbon, environmentally sound, energy supply, and it is marked by the increase of RES penetration and the phase-out of nuclear power plants.

for onshore investments. TenneT (2017) notes that “in future regulatory periods, the efficiency of offshore investments may be assessed using an international TSO benchmark”.

7.4.2.4 BELGIUM

Belgium offers dedicated incentives for 'strategic investment projects', that consist mainly of an additional remuneration over the project (Elia, 2017b). Strategic investments are mainly aimed at improving EU integration and may be entitled to receive an additional mark up. According to Elia (2017b), “this additional remuneration is calculated as a percentage of the actual cumulative amount dispensed (investment amounts are capped per year and per project).” The additional incentive, however, is linked to the OLO rate (free-risk rate). The mark up is applied at full rate if the OLO rate is equal or below 0.5%. If the OLO is higher, the mark up is reduced proportionally, capped at 2.16%. The application of the additional remuneration is also conditioned to on time commissioning of the investment, subject to penalties otherwise.

7.4.3 SUMMARY AND INTERPRETATION

Table 24 shows a summary of the dedicated incentives with a focus on offshore investment. Four countries out of five considered in our analysis have some form of dedicated incentive scheme (Denmark being the exception due to a different regulatory regime). Table 24 maps the dedicated incentives in these four countries. Dedicated incentives are categorised into two groups: increased remuneration and risk mitigation measures. In Germany and the Netherlands, the schemes are focused on reducing the risk for TSOs. Both countries provide an exemption from capex efficiency benchmarks, while the Netherlands also provides a reduction in the depreciation period. Belgium exclusively provides additional remuneration while Great Britain provides additional remuneration as well as offering risk mitigation measures in the form of advance timing of cost recognition.

Table 24: Summary of dedicated incentives





				
Increased Remuneration	x			x
Risk Mitigation Measures				
Exemption from capex efficiency benchmarking		x	x	
Advance timing of cost recognition	x	x	x	
Reduced depreciation period			x	

Figure 40 below combines the economic incentives plot of default national regulatory regimes with the effect of dedicated incentives for offshore investment. In Germany and the Netherlands, as the dedicated incentive schemes focus on reducing the risk for TSOs. the downward trend is indicated on the chart to reflect reduction of risk due (downward) arrow. As the dedicated incentives provide additional remuneration alone, a trend towards

the right is indicated (rightward pointing arrow). In Great Britain additional remuneration along with the risk mitigation measures is provided, and the combined effect is indicated by a right downward-pointing arrow (trend of reducing risk and increase in remuneration). However, it should be noted that these trends have been assessed qualitatively. The experiences with the dedicated incentive schemes in these countries have been too recent to allow sound empirical evaluation of the performance of the schemes. Thus, the quantification of their magnitude is outside the scope of this research

The figure shows that dedicated incentives for Belgium, The Netherlands and Germany provide a push towards the central diagonal line of the graphic, a position where economic incentives would be balanced. In general, this analysis indicates that the application of dedicated incentives has provided a push towards a situation where economic incentives would be better balanced in terms of the trade-off between risks and remuneration. In this approach, regulators must remain aware of the increase in risk due to the complexity of such mechanisms, especially in terms of information asymmetry and transparency.

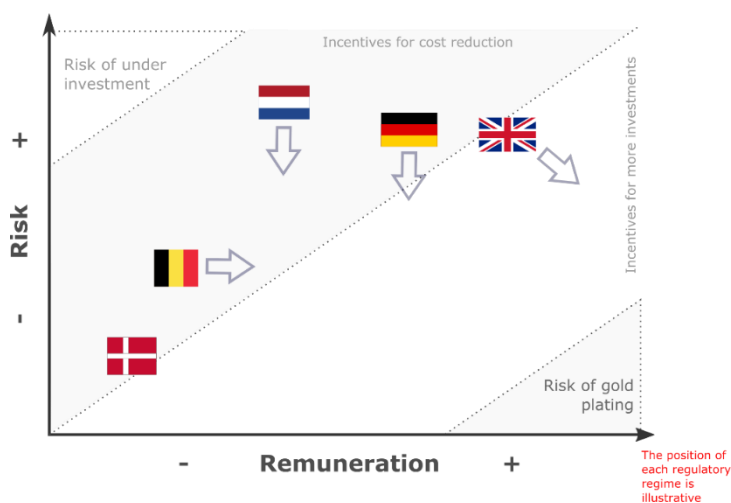


Figure 40: Plot of stylized economic incentives including the effect of dedicated incentives

7.5 CONCLUSIONS

We investigate the economic incentives that are necessary for the development of the offshore grid. A case study approach is utilized in this research. Five countries, namely: United Kingdom, Germany, Denmark and Belgium are studied. This research extends the work of Glachant (2013), and Meeus and Keyaerts (2014) to present the combined impact that the general regulatory regime and dedicated incentives may have on the risk and remuneration for TSOs.

Traditionally, transmission businesses have been remunerated on a portfolio basis. The TSO invests, the investment is included in the RAB, and a WACC is applied to RAB as a whole. Similarly, risk allocation has been set considering the business as a whole, and not taking into consideration the specificity of individual projects.

This model is still the core of transmission regulation in the five cases analysed in this chapter. Since the previous study by Glachant (2013), the default regulatory frameworks of the countries analysed have not changed significantly in terms of their risk and remuneration characteristics.

However, TEN-E Regulation mandates the provision of additional incentives for PCIs if needed. Therefore, in recent years, a new type of case-by-case regulation started being implemented and now coexists with the traditional portfolio regulation. It is observed that recently, regulators have started providing additional dedicated incentives for necessary or strategically important investments.

The trend of providing dedicated incentives modifies the risk and remuneration characteristics set by the general national frameworks. This qualitative analysis indicates that in Germany and the Netherlands, the application of dedicated incentives indicates a trend towards reduction of risk while in Denmark it reflects an increase in revenue. In Great Britain, a trend of both reducing risk and increase in remuneration can be observed.

In general, this qualitative analysis indicates that application of dedicated incentives can be considered a valid approach by countries that are likely to require significant investment in offshore grids. The trend of providing dedicated incentives modifies the risk and remuneration characteristics set by the general national frameworks. The application of dedicated incentives has provided a push towards a better balance of economic incentives in terms of the trade-off between risks and remuneration. However, in this approach, regulators must remain aware of the increase in risk due to the complexity of such mechanisms, especially in terms of information asymmetry and transparency.



8 OFFSHORE GRID INVESTMENT III: CROSS-BORDER COST ALLOCATION IN THE MESHED OFFSHORE GRID CONTEXT

8.1 INTRODUCTION

The Position of this chapter in the overall scheme of this project structure has been presented in Figure 41

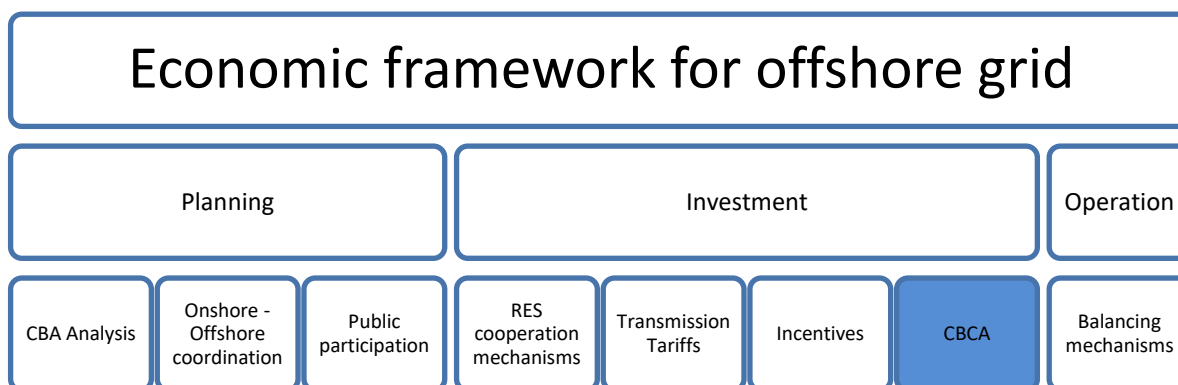


Figure 41: Illustration indicating the position of this chapter in the overall report structure

The development of a meshed offshore grid (MOG) would consist of the development of several projects with strong interactions and possible complementarity. Furthermore, these projects can be expected to involve several actors and borders. In such multi-jurisdictional projects, cross-border cost allocation (CBCA) would be crucial for ensuring the timely and effective development of such projects. Furthermore, the development of a meshed offshore grid will be evolutionary. Therefore, offshore interconnectors that are inherently multi-jurisdictional and built across borders can be considered an early step in the evolution of a MOG.

In this chapter, we discuss cross-border cost allocation for transmission infrastructure projects in the context of developing a meshed offshore transmission grid. The research utilises a case-study approach. An analytical framework is developed based on earlier work done by the Florence School of Regulation on the topic of CBCA for this analysis. In the first step, CBCA decisions on three offshore interconnectors, namely: Biscay Gulf interconnector, COBRACable and EWIC interconnector are assessed based on the analytical framework. The assessment provides recommendations for improving CBCA decisions for such projects. In the second step, the insights from the first step along with the analytical framework are used as a basis for an analysis leading to a recommendation on good practices for executing CBCAs in the context of a meshed offshore grid development.

The chapter is structured as follows. In Section 8.8.2, a summary of different cost allocation methodologies based on the literature review by Jansen et al., (2015) and De Clercq et al., (2015) is present. In Section 8.8.3, we present the theoretical framework for assessing the cross-border cost allocation decision. Section 8.4 provides the assessment of the three interconnector CBCA case studies based on the analytical framework. In this chapter, the insights from the case studies and the framework are applied to develop recommendations on good practices

for executing CBCAs in the context of a meshed offshore grid development. The key insights from this research are presented in Section 8.8.5.

8.2 REVIEW OF COST ALLOCATION METHODS

In literature, De Clercq et al., (2015) discuss three approaches for cost allocation, namely: Network Flows, Economic Beneficiaries and Postage Stamp. Jansen et al., (2015) use the same three elements in their classification, except that the authors rename 'economic beneficiaries' as 'beneficiary pays'. In this section, we provide a brief review of cost allocation methods that have been proposed in the literature. In the following sections, we summarise various approaches to cost allocation based on the literature review conducted by Jansen et al., (2015) and De Clercq et al., (2015).

8.2.1 BENEFICIARY PAYS

In this approach, the cost is allocated to the beneficiary of the transmission expansion project. Three methods for applying the beneficiary pay principle are illustrated in literature, namely: proportional to benefits method, positive net benefit differential method, and the Shapley value method based upon game theory.

In the proportional benefits method, the costs are allocated such that every stakeholder would have the same cost-benefit ratio. In the net-benefit differential method, if the net benefit at a system level is positive, any net loser is compensated by the benefiting stakeholders. According to the description of Jansen et al., (2015) *“Stakeholders that obtain highest positive net benefits have to pay the highest compensation to negatively affected stakeholders, and vice versa”*.

The Shapely value method first introduced by Shapley, (1953) requires the application of cooperative game theory. The approach is described by Hart, (1989) as follows: *“The value of an uncertain outcome (a 'gamble', 'lottery', etc.) to a participant is an evaluation, in the participant's utility scale, of the prospective outcomes: It is an a priori measure of what he expects to obtain (this is the subject of 'utility theory'). In a similar way, one is interested in evaluating a game; that is, measuring the value of each player in the game.”*

According to De Clercq et al., (2015) the specific application of this method in the context of electricity networks for Brazil is called Aumann-Shapely method. The authors describe it as follows: *“locational network charges are computed for the used fraction of the grid as the cost of the network assets used by agents according to the Aumann-Shapley theory. This theory states that each agent is responsible for the average incremental use it makes of the network when joining a great coalition that ends up containing all generators and loads in the system.”*

TEN-E Regulation on CBCA method

The TEN-E regulation state that: *“The efficiently incurred investment costs, which excludes maintenance costs, related to a project of common interest falling under the categories set out in Annex II.1(a), (b) and (d) and Annex II.2 shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the*

Member States to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Member States.”. Therefore, it can be said that the regulation appears to envision an approach towards CBCA decisions that are based on the beneficiary pays principle.

8.2.2 NETWORK FLOWS

In this method, the costs are allocated according to the network flow that is caused by the user. There are five methods of applying flow-based approach, namely: average participation, incremental cost related pricing (ICRP), area of influence, marginal participation and mean participation. According to Jansen et al., (2015) and De Clercq et al., (2015) marginal participation and mean participation methods are not feasible alternatives.

The average participation method is based on the assumption that at a node, the power inflow contributes to the power outflow proportional to the volume of the power outflow (Olmos and Pérez-Arriaga, 2009). The relevant users are allocated the costs based on the ‘tracked’ usage of the line. Between the producers and consumers, the costs are divided 50-50. In the ICRP method, the marginal cost of new transmission infrastructure development that would be needed due to any increase in demand or generation at a node is calculated. In the area influence method, the cost is allocated to the identified beneficiaries based on their use of transmission expansion (De Clercq et al., 2015).

8.2.3 POSTAGE STAMP

In this approach, the costs are allocated equally to all users. There are two ways to apply this method that have been discussed by NSCOGI, (2013) namely: Louderback method and min/max contribution. A third approach illustrated is the use of the simple equal share principle.

The Louderback method can be considered as a combination of beneficiary pay and postage stamp. Initially, a direct cost is determined and allocated to the relevant stakeholder. The remaining residual cost is shared between the stakeholders in proportion to the difference between the ‘stand-alone cost’⁹³ and their direct contribution. In the min/max method, the “*residual cost contribution of those responsible for connecting offshore wind parks to the onshore grid is the average load factor of the offshore wind park times interconnector costs at minimum, and interconnector costs times nominal power at maximum*” (Jansen et al., 2015). Finally, the equal share principal can also be considered as a postage stamp method. In this method, each hosting country makes an equal contribution towards the costs.

8.3 ANALYTICAL FRAMEWORK

The analytical framework used in this research is developed based on earlier research by the Florence School of Regulation on the topic of CBCA. Meeus and He, (2014) provided guidance on improving CBCA methods used for projects of common interests (PCIs) that fall within the framework of the Trans-European Network for Energy (TEN-E) regulations (European Union, 2013).

⁹³ Meitzen and Larson, (1992) defines stand-alone costs as “the cost of providing one service (or group of services) of a multiproduct firm on its (their) own, without producing any of the firm’s other services.”

According to Article 1, Paragraph 1 of the TEN-E regulation text *“This Regulation lays down guidelines for the timely development and interoperability of priority corridors and areas of trans-European energy infrastructure set out in Annex I (‘energy infrastructure priority corridors and areas’)”*. PCIs can be defined as projects that generally concern two or more member states (or at least indirectly impact two or more member states) and are considered to be strategically important for ensuring that the EU reaches its climate and energy policy goals (Meeus and He, 2014).

The research identified and discussed three avenues for innovation in CBCA decisions: 1) using the CBA as the basis for the CBCA decision. 2) Entering into a formal contract between involved parties to ensure execution of CBCA agreement. 3) Making a CBCA agreement for a group of complementary projects rather than for single projects. It concluded that innovation in the application of CBCA agreements is happening, but there continues to be room for a higher level of innovation. It was recommended that NRAs consider the above three dimensions for possible innovation, while Agency for the Cooperation of Energy Regulators (ACER) could play a role in identification and dissemination of good practices as well as set a minimum standard.

In a follow up to the earlier research summarised above, Meeus and Keyaerts, (2015), assessed the first set of CBCA decisions for PCI projects. Twelve projects received CBCA decisions from the relevant National Regulatory Authorities (NRAs) while one decision was made by the ACER. The research assessed compliance of these CBCA decisions with the TEN-E regulation, ACER recommendations and the FSR recommendations. It should be noted that in this research, both gas and electricity projects were considered.

The analysis led to six recommendations in the forms of lessons learnt from the first set of CBCA decisions. The six recommendations are summarized by the authors as follows: *“[1] revisit the significance threshold and the interaction with the Connecting Europe Facility, [2] promote the good practice of using market tests to improve the cross-border cost allocation decision, [3] require a complete cross-border cost allocation decision, [4] continue to use the results of the cost-benefit analysis to facilitate innovative cross-border cost allocation decisions, [5] continue coordinating these decisions for strongly interacting projects, and [6] start including binding commitments in the decisions, especially with respect to the commissioning date”*. Figure 42 illustrates the six elements used in this assessment.

In December 2015, ACER provided its own set of recommendations *on “good practices for the treatment of the investment requests, including cross-border cost allocation requests, for electricity and gas projects of common interest”* (ACER, 2015d).





Figure 42: Illustration of the six elements of the framework for assessing the CBCA decisions for offshore interconnectors

In the research presented in this chapter, we use the six recommendations from Meeus and Keyaerts, (2015) as the fundamental elements for the assessment framework. Based on publicly available information of CBCA decisions, we evaluate the extent to which CBCA decisions for the three interconnectors case studies namely; Biscay Gulf Interconnector East-West Interconnector (EWIC) and the COBRACable adhere to the six elements. Therefore, we assess where any innovative approaches have been applied for offshore interconnector CBCA decisions. Based on this assessment, we provide recommendations on best practices that can be implemented to ensure a robust offshore infrastructure development in the North Sea. In the following part of this chapter, we discuss the six elements of this analytical framework in greater detail.

8.3.1 INTERACTION OF SIGNIFICANCE THRESHOLD WITH EU FUNDING

TEN-E regulation envisions an approach towards CBCA decisions that is based on the beneficiary pays principle. It is stated in the regulation that: *“The basis for the discussion on the appropriate allocation of costs should be the analysis of the costs and benefits of an infrastructure project on the basis of a harmonised methodology for energy-system-wide analysis, in the framework of the 10-year network development plans prepared by the European Networks of Transmission System Operators under Regulation (EC) No 714/2009 and Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks (18), and reviewed by the Agency. That analysis could take into consideration indicators and corresponding reference values for the comparison of unit investment costs”*. Furthermore it states, *“The efficiently incurred investment costs, which excludes maintenance costs, related to a project of common interest falling under the categories set out in Annex II.1(a), (b) and (d) and Annex II.2 shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the Member States to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Member States.”*

Furthermore, with regards to application of the beneficiary pays principle, ACER, (2013) recommended that “*only countries with a significant positive net benefit should contribute to provide compensation*”. A 10% of the total net positive benefits significance threshold was accorded for a country to be considered for cost allocation, except in specific cases, where it could be lowered. It is argued that the complexity of coordinating a CBCA decision with many small beneficiaries would lead to a significant transaction. From an economic perspective, significance could be utilised as a proxy for certainty, and thus, in this case, only countries that are adequately certain of benefitting would be allocated the costs.

In their analysis of the CBCA decisions, Meeus and Keyaerts (2015) observe that project developers use significance threshold as an argument for justifying their requirement for EU funding. This may lead to more than necessary requests for EU funding which is limited. Five PCIs assessed during the Meeus and Keyaerts, (2015) study, justify their CBCA decision on the basis of the significance threshold. Therefore, the recommendation from the study was to revisit the interlinking of the significance threshold and the request for EU funding. Thereby ensuring no misuse of this argument for justifying incomplete CBCA decisions.

8.3.2 USE OF MARKET TESTS FOR ASCERTAINING COMMERCIAL VIABILITY

According to the TEN-E Regulation: “*The efficiently incurred investment costs, which excludes maintenance costs, related to a project of common interest falling under the categories set out in Annex II.1(a), (b) and (d) and Annex II.2 shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the Member States to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Member States*”. Furthermore, one of the criteria for receiving financial assistance is that: “*the project is commercially not viable according to the business plan and other assessments carried out, notably by possible investors or creditors or the national regulatory authority. The decision on incentives and its justification referred to in Article 13(2) shall be taken into account when assessing the project’s commercial viability*”. Therefore, demonstrating commercial (non) viability becomes a vital part of the decision process on approval of EU assistance and any dedicated incentives that may be for such projects.

Market tests can complement the results of the cost-benefit analysis regarding commercial revenue projections and thus aid in improving CBCA decisions. In the context of the Gas projects, market tests are already used for testing the commercial viability of projects (and for assessing exemption under Article 36 (6) of Directive 2009/73/EC). The commonly used structure of market tests in gas is carried out in two phases. In the first phase (expression of interest phase), an Expression Of Interest (EOI) for contracting capacity and connecting to the line was requested from all potential users. In the second phase (booking phase), binding requests for contracting capacity and connecting to the line were requested. However, in the electricity projects, market tests are currently not utilised. The observation mentioned above was supported by the assessment presented by Meeus and Keyaerts, (2015). In four gas PCIs, commercial revenue was used for making CBCA decisions. The study recommends that market tests be promoted to improving CBCA decisions. Assessment of approaches for conducting market tests for electricity infrastructure projects is outside the scope of this research.



8.3.3 REACH A COMPLETE CBCA DECISION

The TEN-E regulation does not mandate the NRAs to provide a complete CBCA decision for the projects. An incomplete decision would mean that the NRAs agree on a cost allocation that is based on assigning part of the costs to the Connecting Europe Facility (CEF). The decision can be then revisited later depending upon the decision on the EU funding request. As not all EU funding requests may be granted, an incomplete CBCA decision may delay projects. Such a scenario would be contradictory to the stated goals of the TEN-E regulations.

Meeus and Keyaerts, (2015) observed that seven projects had an incomplete CBCA decision. The projects were dependent upon funding from the CEF with the decisions on these requests still pending. Therefore the study recommended that a complete CBCA decision should be a requirement. The decision can consider scenarios with and without EU funding as well as with and without commercial revenues.

8.3.4 INNOVATIVE CBCA DECISIONS BASED ON CBA AND BEYOND

As quoted earlier, the TEN-E regulation mandates that the negotiations of CBCA decisions should be based on the CBA. The concerns regarding investment distortions arising from a non-alignment of costs and benefits were highlighted by Meeus and He, (2014). According to this research, these distortions could take the form of *“delay in commissioning date, or suboptimal project dimensioning or routing”*. The authors suggest *“A complete improvement would be to allocate the costs strictly in proportion to the benefits”*. The suggested minimum standard is that if a partner country is a net loser, and then such a partner should be compensated to ensure minimising of a delay due to this issue. However, the study emphasises that countries could utilise innovative approaches that go further than the suggested minimum standard, which would enable greater commitment of all stakeholders towards the project. On this issue, ACER, (2013) recommends that *“unless the relevant NRAs agree otherwise, compensations are provided only if at least one country hosting the project is deemed to have a negative net benefit”*.

Meeus and Keyaerts, (2015) observed that only three projects (all were gas) went beyond the earlier suggested minimum standard, which depends on the CBA. It was recommended that the CBA results must be continued to be used as the fundamental basis for designing innovative CBCA decision.

8.3.5 CONSIDERING PROJECT INTERACTIONS

Meeus and He, (2014) define complimentary projects as those where *“the value of one project depends on the existence of the other, which then also means that the same applies to the investment cost allocation across borders”*. The separate CBCA decision in such a scenario may lead to a distortion in the development of these projects. To mitigate this concern, it is recommended that as the ‘minimum standard’ for projects that are strongly complementary, a cluster approach, in which these projects are considered as one single project, is utilised for coordinating the CBCA decision.

The three gas projects assessed during the Meeus and Keyaerts (2015) study acknowledge and consider interaction with other projects in corresponding CBCA decisions. It should be noted that none of the projects was



for electricity. The authors note difficult in gathering information on analysing this aspect. The study recommends the coordination of CBCA decisions for strongly interacting projects

8.3.6 IMPLEMENT BINDING COMMISSIONING DATE COMMITMENTS IN CBCA DECISIONS

Meeus and He, (2014) suggest that while building cross-border transmission infrastructure projects, there exists a risk of building 'bridges to nowhere'. The phrase means the possibility of risk of stranded costs to one party due to unilateral delays or inability of one party to honour the initially agreed timeline. Therefore, it recommended that CBCA decisions should be formalised as a binding contract between the involved parties. Such a step would aid in guaranteeing execution of the CBCA. A binding agreement can be foreseen to provide greater commitment towards the project by all parties, and therefore it can be considered as an avenue for mitigating the problem of 'bridges to nowhere'.

Mfeeus and Keyaerts, (2015) identify four projects that have a CBCA decision that includes compensation. All four projects were gas projects. In their analysis, the compensation was not dependent on the commissioning date. The study recommends the inclusion of binding commitments in CBCA decisions, especially concerning the commissioning date.

8.4 CBCA FOR OFFSHORE INTERCONNECTOR

In this section, the analytical framework discussed earlier is applied to assess the CBCA decision of three offshore infrastructure projects, namely: EWIC, COBRACable and Biscay Gulf. This chapter is structured as follows. In Sections 8.4.1, 8.4.2, 8.4.3, there is an introduction of the three projects under consideration in this paper. In Section 8.4.4, an assessment based on the analytical framework and the implications for the meshed offshore grids (MOGs) development is presented. It should also be noted that while researching for suitable case studies, it was observed that very few, if any, CBA and CBCA documents were readily and explicitly available for scrutiny. Thus, the scope of this study was constrained by this limitation.

8.4.1 CASE I: BISCAY GULF INTERCONNECTOR

The Biscay Gulf project is envisaged to connect Cubanezais, France and Gatica, Spain with two 100MW rated separate HVDC links. The main reason for the development of this project is to reduce the isolation of the Iberian Peninsula (Spain and Portugal), from the rest of European electricity system, thereby enabling greater integration of the European energy market. The estimated cost of this project is €1750 million. The French TSO Réseau de Transport d'Electricité (RTE) and the Spanish, TSO Red Eléctrica de España (REE), would own the interconnector jointly. 70% (370 KM) of the project route is in France, and 30% is in Spain. The expected commissioning date for the project is 2025. The Biscay Gulf project has been included in the ENTSO-E Ten Year Network Development Plan (TYNDP) since 2012. The project was awarded the PCI label in 2013, 2015 (PCI 2.7) and 2017. The analysis conducted in this research is based on RTE & REE, (2017).

8.4.2 CASE II: EAST-WEST INTERCONNECTOR (EWIC)

In July 2006, the Irish government requested the Commission for Energy Regulation (CER) to arrange a competition for the construction of an East-West Interconnector (EWIC) to Britain. It is a point-to-point project.



The main reason for the construction of the EWIC was to ensure adequate supply in Ireland after ESB Power Generation announced in 2007 its intention to withdraw approximately 1,300 MW of capacity by 2010 [16]. Furthermore, building this interconnector would reduce curtailment of wind energy. The EWIC can be classified as a shore-to-shore interconnector, neither offshore generation nor other offshore cables are connected. EWIC is a “Project of European Interest” and was included in the EU TEN-E Priority Interconnection Plan, which can be regarded as one of the predecessors of the PCI program. This analysis of the EWIC case is based on the Eirgrid business case document (Eirgrid, 2008).

8.4.3 CASE III: COBRACABLE INTERCONNECTOR

COBRACable is a planned (operational by 2019) 700MW subsea interconnector between Denmark and Netherlands. The ownership of this subsea cable is shared between the Dutch TSO TenneT and the Danish TSO Energinet.dk. It is a point-to-point project with the option of integrating other projects. According to TenneT, this project is motivated by four long-term objectives: 1) To facilitate the transport of renewable energy. 2) To form a crucial part of a robust interconnected European electricity grid. 3) To enhance the security of supply in the Northwest European electricity market. 4) To enhance the level playing field in the internal European electricity market. The COBRACable has acquired the PCI status; it was listed both on the 2013 and on the 2015 PCI list. The evaluation of the COBRACable in this research is based on COBRACable business case document (TenneT, 2013).

8.4.4 ANALYSIS

8.4.4.1 INTERACTION OF SIGNIFICANCE THRESHOLD WITH EU FUNDING

In the Biscay Gulf case, the national impact on non-hosting countries was evaluated by the TSOs. The results suggested that 15-40% of the gross benefit would be gained by non-hosting countries. Furthermore, the study indicated that the most impact was in Germany and Portugal, but this impact was “*small and lies within the uncertainty range of the calculation*” (may also be ‘event negative in the case of Portugal’). Therefore, these countries are excluded from bearing the costs of the projects. The CBCA decision does not provide numerical or percentage values for the impacts. Apart from commercial non-viability, other stated reasons for requesting CEF funding were the existence of positive externalities such as security of supply, market integration, sustainability and innovation that do not contribute directly towards improving the commercial viability. Although the share of benefits to the non-hosting countries is explicitly mentioned in the CBCA document, it is not used as a reason for requesting CEF funding.

In the COBRACable business states the following reasons for awarding of the EEPR support: “*EEPR supports the construction, laying and connection of the cable, and the research and development activities on new technologies necessary for the connection of wind farms to the cable. The motivation for awarding this grant relates to the possibility to connect new offshore wind farms to the cable as a first step towards a meshed North Sea offshore grid.*” Therefore, it can be concluded that the significance threshold was not a basis for providing support.



As the EWIC case was from an era before the advent of the TEN-E regulation, the significance threshold did not exist and thus was not used as a reason for requesting. Furthermore, the CBA was focused only on Ireland. According to the publicly available information the following reason is quoted for providing EEPR support: *“This will be the first electricity interconnection between Ireland and the island of Great Britain. By increasing electricity interconnection capacities and allowing possible integration of offshore wind energy, the project will enhance security of supply and diversification of sources of energy for Ireland.”* (See: http://ec.europa.eu/energy/eepr/projects/files/electricity-interconnectors/uk-ie_en.pdf).

8.4.4.2 USE OF MARKET TESTS FOR ASCERTAINING COMMERCIAL VIABILITY

According to the TEN-E regulations, to be eligible for EU funding it is required to demonstrate that the project is *“commercially not viable according to the business plan and other assessments carried out, notably by possible investors or creditors or the national regulatory authority.”* The CBCA decision for the Biscay Gulf uses the CBA as the basis for indicating the non-viability of the projects. No market tests in line with or like those conducted by the gas sector are utilised to supplement the results of the CBA in either of the three cases that have been analysed in this research.

8.4.4.3 REACH A COMPLETE CBCA DECISION

The total project cost of the Biscay Gulf project is estimated to be €1750 million. The developers agreed to bear the cost of the project on an equal sharing basis (50% - 50%). The project developers requested CEF subsidy of €700 million. The two project developers had also agreed to revisit the decision if the total approved CEF funding was below €350 million. Eventually, a CEF funding of €578 million was eventually approved (European Commission, 2017a). An innovative approach was utilized in allocating the CEF subsidy between the two project developers. This was done to ensure a positive NPV for France, which can be attained only if the project cost contribution of RTE is below €528 million. It was agreed that €350 million from the CEF funding that gets approved would be attributed to RTE and the rest for REE. To illustrate, out of the €578 million approved CEF grant, RTE would be allocated €350 million while REE would be allocated €228 million. Thus, the total project contribution of RTE would be €525 million (below the €578 million threshold), while that of REE would be €647 million. Any cost overruns would be shared 62.5% by REE and 37.5% by RTE. The operation and maintenance costs would share 60%-40% between RTE and REE. The CBCA decision, in this case, can be considered incomplete as it was dependent on the results of the CEF funding request. The CBCA agreement did not provide alternative understanding in case CEF funding was not awarded. Especially, if the CEF funding award had been below €350, the revisiting of the decision may have led to delays in the development of the project.

The COBRACable received a European Energy Program for Recovery (EEPR) subsidy of € 86.5 million out of a total project cost of €621 million. The remainder of the cost will be shared between the two project developers in a 50-50 ratio. In the document assessed, the amount of grant approved is already known. However, there is no clarification on whether the cost allocation may (or may not) be modified in case of any change in the grant level.



Therefore, the CBCA decision, in this case, can be considered incomplete as EU funds were requested (and retained) for the development of the project.

The EWIC project received €110 Million funding from the EEPR out of a total project cost of €600 Million. The rest of the cost was borne by EirGrid. Therefore, the CBCA decision, in this case, can be considered incomplete as EU funds were requested (and utilised) for the development of the project.

8.4.4.4 INNOVATE CBCA DECISIONS BASED ON CBA AND BEYOND

In accordance with the TEN-E regulation (European Union, 2013), the Biscay Gulf project developers have conducted a CBA. The CBCA decision is based on the results of the CBA. The CBA does not identify any significant net loser. It should be noted that in the case of Portugal there may be insignificant and uncertain “event negative” benefits. However, the cost and benefits are unbalanced. In this case, the investment undertaken would be 68% in France and 32% in Spain, while the distribution of benefits is to the contrary. The benefits are projected to be 65% in Spain and 35% in France. Based on the findings of the CBA, the NPV projections for the two countries were calculated and used as a basis for cost allocate decision. Overall, some degree of innovation can be attributed to the CBCA decisions as although the investment costs were to be shared 50/50; it was ensured that RTE would be given precedence for the CEF funding to ensure a neutral French NPV.

The COBRACable CBCA decision was based upon the CBA that was conducted by the project promoters. As the European Commission had yet not approved the ENTSO-E CBA 1.0 methodology, the CBA applied for the COBRACable can be considered ‘ad hoc’. The part of the investment that is not covered by the EEPR grant would be borne by the two project developers: the Dutch TSO TenneT and the Danish TSO Energinet.dk on a 50-50 basis. There is no information on how the cost allocation may (or may not) differ if any change occurs in the EEPR funding. Therefore, it can be concluded that no innovation is observed in the CBCA decision.

No indication of any innovative approach towards CBCA can be observed in the EWIC case. The project developer EirGrid did use a CBA for assessing the project and to apply for inclusion in the EU TEN-E Priority Interconnection Plan. However, the CBA only considered benefits for Ireland in the analysis and all the costs were eventually allocated to Ireland. It is important to note that the business case for the EWIC interconnector was developed in 2008. This was much before the existence of the TEN-Regulations. Therefore, no standard CBA methodology for such transmission infrastructure projects was available to the project developer.

8.4.4.5 CONSIDERING PROJECT INTERACTIONS

The ENTSO-E CBA methodology (ENTSO-E, 2015a) has been used by the Biscay Gulf project developers. The CBCA decision is based on the results of the CBA. According to our earlier research on CBA (P. Bhagwat et al., 2017; P. C. Bhagwat et al., 2017; Keyaerts et al., 2016), the ENTSO-E’s CBA 1.0 and 2.0 use a set of scenarios built based on from the “four visions” from the TYNDP 2016. The CBA research also indicated that the scope of



these visions is somewhat limited as the main variation in the scenarios is the projected level of renewables in the future generation mix.

COBRACable is the first planned interconnector linking Netherlands and Denmark, and no other interconnection is planned. Therefore, the cost and benefit calculation of COBRA is not clustered with other new investment projects. Even if there were other new investment projects, there would most likely be no argument for clustering, because the projects would probably be competitive. One reference grid or baseline is applied for the calculations of socioeconomic value. It appears that a thorough analysis was done to assess the future interconnection capacities. However, a sensitivity analysis of the CBA results to construction (or not) of probable future projects was not conducted. The business does consider the impact of the interconnections on *“the reduced congestion revenues at other interconnections on the cost side”*.

In the EWIC case, the interactions with other projects were not considered in the cost allocation decision. The two interconnectors in operation during the development of the business case: Moyle (subsea) Interconnector (450MW), and the North-South (onshore) Interconnector (330 MW) have been acknowledged. Furthermore, two proposed electricity interconnectors, another North-South (onshore) Interconnector and a second East-West interconnector linking Ireland with the GB network in Wales have also been mentioned. However, the CBA is solely focused on the EWIC interconnector and does not consider the positive or adverse effect from the development of any other interconnector projects on its business case.

8.4.4.6 IMPLEMENT BINDING COMMISSIONING DATE COMMITMENTS IN CBCA DECISIONS

In the CBCA documents of the Biscay Gulf project, no commitments on any specific commissioning date are provided by the project developers. However, a schedule is provided, indicating the expected end of the permitting process to be in mid-2023 followed by the finalisation of the first construction phase in the second half of 2024. The expected commissioning of the project has been indicated as in the year 2025.

The publicly available documents on the COBRACable interconnector do not indicate any agreement between the project developers on compensation for delays or non-commissioning of the project by a date. The business case does provide key dates (in a month, year format, except for Board approval from Energinet.dk (November 12th, 2013) and TenneT (November 28th, 2013)) in the project planning section. The COBRACable is expected to be in operation in March 2019. Interestingly, the COBRACable business case document states that *“On May 7, 2013 the European Commission has sent a pre-termination letter stating that the European Commission intends to end the EEPR grant if no investment decision has been taken on December 31, 2013. However, based on a discussion with representatives of DG ENER on June 25, 2013 it is probable that the EEPR will be continued if a final investment decision will be taken ultimately in May 2014. This final investment decision assumes approval of TenneT and Energinet as well as the national regulators in the Netherlands and Denmark.”*

The Irish TSO EirGrid entirely developed the EWIC project. Therefore 100% cost other than the grant was allocated to EirGrid. Therefore, binding commitments can be considered irrelevant in this case as only one project



developer was involved in the development of this interconnector. Thus, this element of the framework is not applicable to the EWIC case.

8.4.4.7 COMPARATIVE ANALYSIS

Table 25: Summary table for the case studies.

	Biscay Gulf	COBRACable	EWIC
Use of significance threshold for CEF	Not explicitly	EEPR grant was provided for reasons of Innovation	No – CBA only considered Ireland
Market tests	No	No	No
Binding contract	No	No	N/A - 100% by EirGrid
Considering project interactions	ENTSO-E CBA has been used	Impact on congestion revenues at other interconnections is considered in CBA	Interactions were not considered in the business case
CBCA Innovation	Some degree innovation used to ensure positive French NPV.	No – 50/50 with EEPR grant	No (Pre-TEN-E regulation)
Complete CBCA Decisions	No – CEF grant	No - EEPR grant	No - EEPR grant.

In Table 25 a summary of the assessment of the case studies based on the analytical framework is presented. It is evident that the six FSR recommendations, which form elements or the basis of the assessment framework for CBCAs, remain relevant from an offshore infrastructure development perspective. It can be observed that none of the assessed case studies received a complete CBCA. Each project depended to a varying degree on European Union funding. Furthermore, no market tests were conducted for any of the projects nor were the existence of any binding contract with compensations for completion of projects on a pre-agreed date observed in publicly available documents. It should be noted that the dimension of using binding contracts is irrelevant in the EirGrid case, as the project was developed by a signal project developer (i.e. EirGrid). Thus, the observations on the above mentioned three dimensions of the assessment framework are in line with those of Meeus and Keyaerts, (2015). Therefore, these recommendations not only remain relevant but there is also an indication that there is substantial scope for improvement in CBCA decision in this regard.

The use of a CBA as the basis for the CBCA decision is evident. With the implementation of the TEN-E regulations, PCIs are required to conduct a CBA based on the ENTSO-E CBA methodology. Therefore, it can be foreseen

that CBA would be used as an input during the CBCA decision making process. In the Biscay Gulf project, some degree of innovation is observed. The evidence of project developers exploring possible innovation in CBCA decisions can be considered a positive step forward and as such project developers should continue to explore the possibility of applying innovation to CBCA. Project interactions are being considered to the extent required by the ENTSO-E CBA methodology. However, no evidence of coordination between CBCA decisions of the complimentary project or any such consideration was observed. Finally, the significance threshold is not used for requesting EU support, and the EU grants were provided for other reasons. However, in the Biscay bay case, the share of benefits to the non-hosting countries is explicitly mentioned.

8.4.4.8 MESHED OFFSHORE GRID PERSPECTIVE

In the context of the meshed offshore grid development too, the FSR recommendations arising from the six elements of the framework continue to remain relevant. However, four elements, namely; binding contracts, complete CBCA decisions, considering project interaction and the linkage between significance threshold and EU funding can be identified as being especially more relevant from the meshed offshore grid development perspective. We have already highlighted that there is some level of innovation that is already taking place in CBCA decisions.

Individual transmission infrastructure projects developed as part of a meshed offshore grid can be considered complementary due to the interlinking. Complimentary projects as those where *“the value of one project depends on the existence of the other, which then also means that the same applies to the investment cost allocation across borders”*. A separate CBCA decision in such a scenario may lead to a distortion (e.g. delays) in the development of these projects. Thus, considering interactions between projects robustly in CBCA decision-making is crucial for enabling development of these projects and in turn the meshed offshore grid. The recommendations of Meeus and He, (2014) can be considered very relevant for such cases. It is recommended that as the ‘minimum standard’ for projects that are strongly complementary, a cluster approach where these projects are considered as one single project is utilised for coordinating the CBCA decision. One issue with this clustering approach is that the timing of the development of the projects should be not too far apart.

Furthermore, a meshed offshore grid would be a multi-country and therefore multi-jurisdictional project. Its development would entail the involvement of and coordination between several project developers, each of whom may have their own set of unique constraints. There exists a risk of stranded costs due to unilateral delays or inability of one or some parties to honour the initially agreed timeline. Therefore, CBCA decisions should be formalised as a binding contract between the involved parties with explicit specification of non-compliance penalties, especially regarding commissioning dates can be recommended. Such a step would aid in guaranteeing execution of the CBCA and provide greater commitment towards the project from all parties, thereby enabling the avoidance of situations with “bridges to nowhere”.

The third element that is of high relevance from a meshed offshore grid perspective is the use of a significance threshold while allocating costs between the different involved project developers. There is a distinct possibility



that the benefits from various projects that would be developed as part of the meshed offshore grid would be spread across several countries. It is also possible that a significant amount of the benefit could be allocated to non-hosting countries but at a level below the significance threshold. The project promoters may use the significance threshold to request for EU funding and justify incomplete CBCA decisions. The CEF funding is limited and not designed for handling funding requests that arise due to the significance threshold. Thus, the significance threshold may become a barrier to allocating costs effectively. Consequently, this may lead to delays in the development of these transmission infrastructure projects and the meshed offshore grid. Therefore, revisiting the significance threshold and the interaction with EU funding is recommended.

Finally, in such multi-stakeholder projects, negotiations between the different stakeholders can be a complex process. In case of an incomplete CBCA decision, there is a possibility that renegotiations may be required in the event of an adverse EU funding decision. These renegotiations may lead to unnecessary delays in the development of the project. Therefore, a complete CBCA decision is recommended. The decision can consider scenarios with and without EU funding as well as with and without commercial revenues.

8.5 KEY INSIGHTS

In this section, we summarise the key insights from this chapter. A case-study approach is used to discuss CBCA for transmission infrastructure in the context of developing an HVDC meshed offshore grid. An analytical framework was developed based on earlier work done by the Florence School of Regulation on the topic of CBCA for this analysis. In the first step, CBCA decisions of three offshore interconnectors, namely: Biscay Gulf interconnector, COBRACable and EWIC interconnector are assessed based on the analytical framework. The assessment provides recommendations for improving CBCA decisions for such projects. In the second step, the insights from the first step along with the analytical framework are used for providing a recommendation on good practices for executing CBCAs in the context of a meshed offshore grid development.

It is evident that the six FSR recommendations continue to remain relevant from offshore infrastructure development including the meshed offshore grid. In the case studies, none of the projects received a **complete CBCA decision**, no **market tests** were conducted, nor were any **binding commitments** incorporated into the CBCA. Large scope for improvement exists in these three aspects.

The use of a **CBA as the basis for the CBCA decision** is evident. With the implementation of the-E regulations, PCIs are required to conduct a CBA based on the ENTSO-E CBA methodology. Therefore, it can be foreseen that CBA would be used as an input during the CBCA decision making process. It is observed that project developers are **exploring possible innovation in CBCA decisions**. This can be considered a positive step forward and as such project developers should continue to explore the possibility of applying innovation to CBCA.

Project interactions are being **considered** to the extent required by the ENTSO-E CBA methodology. However, no evidence of coordination between CBCA decisions of the complimentary project or any such consideration



was observed. Finally, in the case studies under consideration, the **significance threshold** has not been used for requesting EU support. Not using significance threshold for EU support is a good practice and should continue.

Specifically, in the context of the meshed offshore grid development, we highlight four key recommendations.

Recommendation 1: The coordination of CBCA decisions for complementary projects is recommended. This aspect would be further enhanced with a clustered approach in which a CBCA agreement is reached for a group of projects. Such an approach would enable robust consideration of project complementarities and mitigate any distortions in the development of the projects.

Recommendation 2: Formalization of the CBCA as a binding contract between the involved parties with clear specification of non-compliance penalties, especially regarding commissioning dates is recommended. In a multi-stakeholder environment, such a step can be foreseen to provide greater commitment towards the project by all parties, thereby preventing “bridges to nowhere”.

Recommendation 3: It is recommended to revisit the interaction between significance threshold and EU funding. This step would aid in more effective cost allocation by encouraging complete CBCA decisions as well as enabling effective EU funding allocation, thus reducing avoidable delays in the development of these transmission infrastructure projects.

Recommendation 4: Ensuring complete CBCA decisions is recommended. The decision can consider scenarios with and without EU funding as well as with and without commercial revenues. Such a step would mitigate any delays that may occur due to renegotiations between project developers that may be necessitated by an adverse EU funding decision.



9 OFFSHORE GRID OPERATION I: THE IMPACT OF BALANCING MECHANISM DESIGN ON OFFSHORE WIND FARMS

9.1 INTRODUCTION

The Position of this chapter in the overall scheme of this project structure has been presented in Figure 43.

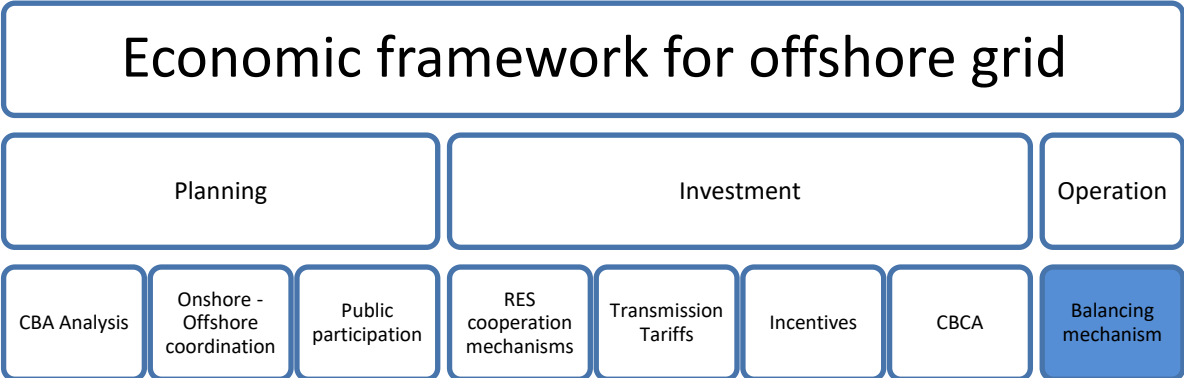


Figure 43: Illustration indicating the position of this chapter in the overall report structure

It is well known that system operators are required to balance the system in real-time to ensure operational security by keeping the frequency within the prescribed limits. In the era of the vertically integrated utility, system balancing was a relatively simple engineering task. The unbundling of the electricity sector that followed the Electricity Directive 96/92/EC (European Commission, 1996) necessitated closer scrutiny of system balancing as now transmission operations were delinked from generation and retail. At the beginning of the liberalisation process, wholesale electricity markets were accepted relatively quickly, but balancing the system in real-time continued to be seen as a technical issue. Gradually, it became clear that what happens in real-time determines how the market parties behave in wholesale markets, i.e. the real-time balancing price influences the intraday, day-ahead and finally long-term prices. Therefore, there was an evolution towards market-based balancing. Balancing markets and their design has been widely described from a different perspective in literature. Van der Veen and Hakvoort, (2016) provide a general review of the literature on this topic. Today, with the advent and increase in penetration of intermittent renewable resources, the need for ensuring robust and well-functioning balancing markets is more challenging than before (Vandezande et al., 2010; Borggreffe and Neuhoff, 2011).

Offshore wind generation is expected to play a significant role in enabling the EU to meet its greenhouse gas (GHG) reduction and renewable energy target in the future (European Commission, 2015). Therefore, it is essential to assess various balancing market design parameters from the perspective of their impact on the operation of the offshore wind farms. This research aims to provide an insight into the “rules of the game” taking into account the specificities of the offshore wind technologies. The design of balancing products and the way that balancing markets are organised can enable the participation of new players or hamper their access to these

markets. This research assesses current balancing mechanisms from the perspective of offshore wind participation both as a balance-responsible party (BRP) and as a balancing service provider (BSP). In the following paragraphs, we introduce these two perspectives.

First, a mal-functioning balancing market⁹⁴ could drive up the cost of imbalanced intermittent generators who are exposed to high imbalance prices. There is a discussion of whether the intermittent renewables should be BRPs at all. According to the Electricity Balancing Guideline (EB GL), a BRP is “*a market participant or its chosen representative responsible for its imbalances,*” In the current electricity directive 2009/72/EC (European Commission, 2009b), intermittent renewable resources are exempt from balancing responsibility.⁹⁵ It can be said that by exempting intermittent renewables from being BRPs, an implicit subsidy is granted to these generators. Such an exemption could be justified for an immature and hard-to-forecast generation as otherwise, the risk of being exposed to high balancing prices could mean a lack of investor appetite. But, by not letting these generators be responsible for the imbalances (and thus costs) they impose in the system, they have minimal incentive to reduce these. A reduction of such imbalances would be positive for the whole system. In that light, the recent Clean Energy Package (CEP) proposes derogation of the balance responsibility exemption (See Article 4 in (European Council, 2019)). Vandezande et al., (2010) in their paper on balancing market design considering growing wind penetration in the system advocated that “*given the variability and limited predictability of wind generation, full balancing exposure is however only feasible conditionally to well-functioning balancing markets.*” This view has been illustrated by Klessmann, (2009). The authors also contend that countries with high wind penetration should “*burden more responsibility and risks on wind generation in order to give them an incentive for cost-reflective market behaviour and as such limit the indirect costs to society. Equal balancing rules for all market participants may for instance encourage wind power producers to provide more accurate forecasts of their generation – in order to reduce their own balancing costs – which may in turn lead to an increased system balancing efficiency.*” The positive impact of full market participation of wind energy in the market has been discussed by Hiroux and Saguean, (2010).

Secondly, besides having intermittent renewables such as offshore wind exposed to the imbalance costs they cause, there is also an active discussion on how to integrate these non-dispatchable generation technologies as BSPs. It is often claimed that a high entry barrier for intermittent renewable resources existed due to the balancing market design being more suited towards dispatchable generation technologies. Borggreffe and Neuhoff, (2011) assess market design in several European countries for their ability to enable the participation of wind technologies. The authors provide a set of market design criteria for the integration of intermittent renewables. One of the objectives of EB GL (2017/2195/EC) is to facilitate the participation of renewables in the balancing market as BSPs (European Commission, 2017b).

We also investigate whether the interests of offshore wind are aligned with the interest of the system as a whole. Therefore, we provide a third perspective to this analysis where we assess the same issues at a system level.

⁹⁴ Distortions in balancing market in terms of market design, procurement, regional cooperation and coordination, and curtailment are discussed by Tennbakk et al., (2016)

⁹⁵Note that some member states such as Denmark (Energinet.dk, 2011) and UK (National Grid, 2011) already allow wind turbines to participate in the balancing market.



The chapter is structured as follows. The next section discusses how balancing works. The analytical framework used for this assessment is then presented in the following section, 9.3. Section 9.4 discusses the different elements of the balancing mechanism from the three perspectives. Finally, the key conclusions are presented in Section 9.5.

9.2 HOW BALANCING WORKS⁹⁶

9.2.1 THE DIFFERENT CATEGORIES OF RESERVES

Figure 44 illustrates the restoration of the system frequency after a frequency deviation.⁹⁷ For this purpose, different types of reserves are activated sequentially. These different types of reserves meet different operational needs; in practical terms, they differ mainly in response time and maximum duration of delivery. The types of reserves which can be grouped under three processes are summarised in Table 2, the nomenclature as used in the SO GL is applied. To provide further clarity, previously used denominations are also presented.

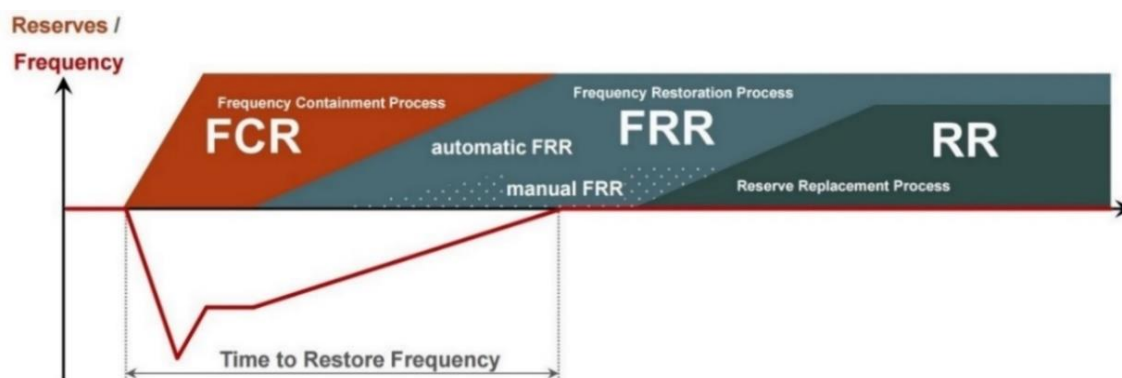


Figure 44: A frequency drop and the reserve activation structure (Elia and TenneT, 2014)

Table 26: Terminology for reserve products (based E-Bridge and IAEW (2016))

	Frequency containment process (FCP)	Frequency restoration process (FRP)		Reserve replacement process (RRP)
Operational reserves defined by SOGL	Frequency Containment Reserve (FCR)	Automatic Frequency Restoration Reserves (aFRR)	Manual Frequency Restoration Reserves (mFRR)	Replacement Reserve (RR)

⁹⁶ This section is based on Schittekatte and Meeus, (2018)

⁹⁷ It should be noted that the activation process shown in this figure is the typical activation process for a TSO with a reactive approach to the activation of balancing energy. Two approaches to the activation of balancing energy are identified in the EU, reactive balancing and proactive balancing (Elia and TenneT, 2014; Haberg and Doorman, 2016; Pentalateral Energy Forum, 2016). The key difference between the two approaches is that with reactive balancing the TSO activates balancing energy to counteract imbalances in real-time, while with proactive balancing the TSO activates balancing energy before real-time based on forecasts of imbalances.

ENTSO-E Operation handbook	CE	Primary Control	Secondary Control	Tertiary Control	Tertiary Control
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Figure 44 shows the occurrence of a frequency drop; a frequency drop is caused due to a deficit of energy in the system, i.e. there is more consumption or less generation than scheduled in real-time. Vice-versa, the frequency would rise. The first source limiting the frequency drop is inertia. Inertia is not depicted in Figure 44. Inertia is an inherent physical property of, for example, turbines.⁹⁸ Inertia slows down a frequency drop/spike immediately after a mismatch between supply and demand and does not need any control signal. In other words, with little inertia, a small difference in supply and demand can cause a very steep frequency drop/spike. Inertia was always valuable for the system, but it was mostly provided for free as it was abundant in the recent past. However, recently, due to the penetration of non-synchronous generation systems, during certain moments not many thermal power plants are connected. Consequently, during those moments, system inertia and thus reliability decreases. This is especially a concern for isolated systems. To limit such issues, there are also methods being developed to obtain inertia from other sources than thermal power plants, so-called 'synthetic inertia provision'.⁹⁹

System inertia slows down the drop/rise in frequency but does not stop the drop/rise. Therefore, almost instantaneously from the moment, the frequency drops/spikes, **Frequency Containment Reserves (FCR)** are activated to stabilise or 'contain' the drop/spike. FCR is the fastest type of reserves and operated using a joint process involving all TSOs of the synchronous area. Within a couple of minutes after the activation of FCR, the Frequency Restoration Process (FRP) starts. First, **automatic Frequency Restoration Reserves (aFRR)** and later **manual Frequency Restoration Reserves (mFRR)** are activated. aFRR are reserves activated automatically by a controller operated by the TSO, mFRR are activated upon a specific manual request from the TSO. The FRP aims to restore the frequency to its nominal value. Finally, after about 15 minutes or more, **Replacement Reserves (RR)**, the slowest type of reserves, can be activated to support or replace FRR. Not all systems have a Reserve Replacement Process (RRP) in place, and this process is not made mandatory by the SO GL.

Although the same categories of reserve products exist in the EU, the exact product definition and the methodologies used for sizing or activation can still differ strongly from one control area to another. The EB GL and the SO GL intend to harmonise most elements of the balancing mechanism, which also paves the way for the more cross-zonal exchange of balancing resources.

9.2.2 THE BALANCING MARKETS

It can be said that two (interrelated) 'balancing markets' exist: balancing capacity markets and balancing energy markets. In this section, balancing capacity markets and balancing energy markets are introduced. The market

⁹⁸ In Art. 2 (33) of the RfG NC inertia is defined as 'the property of a rotating rigid body, such as the rotor of an alternator, such that it maintains its state of uniform rotational motion and angular momentum unless an external torque is applied'. In the same network code also the requirements regarding inertia provision are covered.

⁹⁹ For more information, see also the short video by the North American Electric Reliability Corporation (NERC) explaining concepts as frequency and inertia: <https://vimeo.com/nerclearning/erstf-1/video/146105419>

design could affect the costs for system balancing and also the revenue generation opportunities for market parties.

9.2.2.1 BALANCING CAPACITY MARKET

In the balancing capacity markets, **BSPs are paid in order to reserve capacity for the duration of the contract.** This implies that a BSP cannot commit this capacity in other markets (such as the DAM or IDM). Reserved balancing capacity is expected to be available in real-time, i.e. they have to bid in real-time balancing energy markets. If not, they will have to pay a fine. This does not mean that BSPs, who sold balancing capacity, will finally have to deliver the balancing energy. The activation of balancing energy only occurs when in real-time the balancing energy bid is accepted by the TSO. The idea behind reserving balancing capacity for the different reserve types is to make sure that there is always enough security margin, i.e. enough available back-up balancing resources to deal with unexpected events.

In the balancing capacity market, BSPs offer upward and/or downward balancing capacity. Upward balancing capacity means that a BSP will reserve a margin to inject balancing energy into the system when activated. Upwards balancing energy is needed when there is less electricity supply than demand (energy deficit) — Vice-Versa for downward balancing capacity. Balancing capacity markets can take place months ahead to one day before the actual time of (possible) delivery of the balancing energy. The timing may differ per reserve type. In general, there are different markets for the different types of reserves (FCR, aFRR, mFRR and possibly RR). Also per reserve type, there are possibly different products. The demand for reserves procured in the balancing capacity market is determined in the reserve sizing process, i.e. an analysis conducted by the TSO (coordinated or not with other TSOs) to estimate the necessary reserves of each balancing product in real-time.

9.2.2.2 BALANCING ENERGY MARKET

Real-time system imbalances drive the demand for the activation of balancing energy. If the system imbalance is negative, meaning a deficit of electricity in the system, upward balancing energy is activated by the TSO to restore the balance. Conversely, if the system imbalance is positive, meaning a surplus of electricity in the system, downward balancing energy is activated by the TSO. Upward and downward balancing energy bids for aFRR, mFRR and RR have to be submitted before the balancing energy gate closure time. In most cases the activation of FCR is not remunerated, only its reservation is paid. Van den Bergh et al. (2018) explain that in cases where FCR is symmetric (offering jointly fast upwards and downward energy) its activation is generally not remunerated because (short and fast) activations in both directions would eventually cancel out the payments.

BSPs contracted in the balancing capacity market are expected to offer balancing energy for their contract duration. It is important to note that the price of the balancing energy bid should not be predetermined in the contract of balancing capacity (EB GL, Art. 16(6)). Exceptionally for specific balancing energy products, it can be requested that this rule is not applied. Brunekreeft (2015) remarks that if a bid is selected on the balancing capacity market and its bidder is thus obliged to bid in the balancing energy market, the balancing energy market bid can

be very high in order to avoid commitment. This way the relevant bidder still earns a balancing capacity payment.¹⁰⁰ Other BSPs, without contracted balancing capacity, may also bid in the balancing energy market. Finally, if justified, TSOs have the right to compel BSPs to offer their resources as balancing energy when these are resources are not committed in other preceding markets (EB GL, Art. 18(7)).

9.2.3 EXTENT OF HARMONISATION NEEDED FOR INTEGRATING BALANCING MARKETS

Significant gains in terms of efficiency and an increase in security of supply can be achieved by integrating balancing markets. MacDonald, (2013) estimated that the theoretical benefit of the full integration of balancing markets under hypothetical scenarios of the European system in 2030 could be up to 3 billion € per year. Artelys et al., (2016) indicated that monetary gains could be made by joint dimensioning and procurement of reserves (open for DR and RES) at EU level.

However, it is not straightforward to integrate balancing mechanisms as these are complex, and different national approaches have grown organically to fit local needs best. An important difference between the integration of day ahead (DA) and intraday (ID) markets compared to balancing markets is highlighted by Neuhoff and Richstein, (2016). The authors state that for DA and ID markets, harmonisation is focussed mainly on products, timelines and transmission capacity allocation, while with balancing another crucial challenge is added, namely the harmonisation of operational paradigms. In other words, in itself the alignment of markets is not enough – certain relevant elements of system operation must also be aligned. The EB GL described the principles, market rules and proposals which need to be followed, implemented or developed to allow balancing markets to integrate. As such the discussion presented in this section remains relevant from a meshed offshore grid perspective as well.

In earlier drafts of the EB GL, such as version 3.0 published on the 30th of August 2014, a concept called Coordinated Balancing Areas (CoBAs) was mentioned. CoBAs was defined as *“cooperation with respect to the Exchange of Balancing Services, Sharing of Reserves or operating the Imbalance Netting Process between two or more TSOs.”* The idea behind CoBAs was to follow a phased approach toward full integration of balancing markets. First, regional initiatives (as with the balancing pilots), allowing for more flexibility in design would emerge that would then slowly merge. ACER, (2015e) also confirmed that a regional implementation would be an unavoidable interim step for integration. However, CoBAs were removed from the final version of the EB GL (approved by the MSs on 16 March 2017). The focus was shifted towards a (single) European Target Model. However, CoBAs thinking has not been entirely discarded, and regional initiatives are still deemed to be the way forward as stated by Tennet et al., (2016).

In a document by the Pentalateral Energy Forum, (2016), it is remarked that ACER and ENTSO-E hold differing views on the degree of harmonisation required across regional initiatives. According to ACER, the degree of harmonisation should be sufficient to ensure that a situation with incompatible regions is avoided. The same document states that ENTSO-E is of the opinion that regional balancing initiatives can start without complete harmonisation. It can be said that the final version of the EB GL leans more towards ACER’s view.

¹⁰⁰ Such market behaviour is rather unlikely although not impossible in practice.



Standardised balancing products and a harmonised balancing energy gate closure time (GCT) are the two dimensions whose harmonisation both parties agree is absolutely necessary for integration. The EBGL outlines that standard balancing products need to be defined in Art. 25. However, if requested by a TSO and justified, temporarily specific balancing products might be in place in parallel with standard products (Art. 26(1)). The EBGL also states that these standardised balancing energy products for mFRR, aFRR and RR need to be exchanged on European trading platforms (EBGL, Art. 19, 20 and 21). Regarding the balancing energy GCT, Art. 24(1) of the EBGL firmly states the GCT for standardised products should be harmonised for at least mFRR, aFRR and RR processes. Two no-regret options needed for the integration of balancing markets as discussed by Neuhoff and Richstein (2016), and also agreed upon by ACER (2015c), are the harmonisation of the imbalance settlement period (ISP) (EB GL Art. 53: 15 Min) and the agreement on the pricing rule (EB GL Art. 30: marginal pricing) in balancing energy markets. In addition to the four mentioned dimensions of balancing markets, ACER (2015c) argues that there is a need to go further to avoid diverging regional designs. Additional dimensions identified are principles for (activation) algorithms and TSO-TSO settlement rules. In the document by the Pentilateral Energy Forum (2016) the need to harmonise the activation purposes of balancing energy is added to the view of ACER.

9.2.4 PILOTS ON BALANCING SERVICE BY WINDFARMS

Pilot projects to test the ability of wind farms in providing balancing services are already being conducted. In this section, two such pilots conducted in Denmark and Belgium are briefly discussed. Although both pilots are conducted on onshore wind farms, they can nevertheless provide high-level insights for offshore wind on the ability of intermittent wind generation to provide balancing services to the system and how this process is envisaged.

Sorknæs et al., (2013) discuss the Danish pilot for integrating wind in system balancing. The pilot was conducted at a 21MW wind farm in west Denmark owned by Sund & Baelte. The tests were conducted to assess the ability of the wind farm to provide downward regulation. According to the study, the wind turbines provided downward activation several times during the test period. An illustrative example is provided of hour 24 on 14th February 2011 when an increase of 196% in the wind turbines profit was observed by providing downward regulation. Furthermore, a simulation was conducted of this wind farm providing regulation service during the first 9 months of 2010 which indicated an 8% increase in earnings over this period. However, the production would have reduced by 5% over this period due to the provision of downward regulation. According to the authors *“It has been shown that this proactive participation of wind turbines on a balancing market increases the profit of the turbines, and lets the wind turbines help reduce imbalances in the electricity system.”*

WindVision et al., (2015) discuss the Belgian pilot for using wind farms to provide aFRR services. The pilot was conducted at WindVision’s 81MW Estinnes wind farm. In this study, Eneco acted as the balance responsible party for nominating the available capacity of the wind farm for aFRR. The research focused on technical tests of wind farms for providing aFRR but also provided a high-level view of the ability of the Belgian market design to enable participation of wind power. The research concluded that *“The technical pilot project reveals a significant potential for wind farms to participate in the (downward) aFRR market. It is shown that wind farms are able to provide a*



significant amount of flexibility to the grid (high ramp rates, low minimum technical power requirements,...) and can offer these services in a reliable way (high reliability of nominated aFRR volumes).” However, the research also concludes that the Belgian aFRR market design during the period of the research (pre-EB GL) “*does not facilitate the participation of wind farms in the aFRR balancing capacity and energy markets.*”

9.2.5 PROCESS OF AMENDING THE NETWORK CODES

To amend the balancing market design within a member state, the concerned transmission system operator would be required to make a proposal (complying with the network codes) to the regulator who would make the final approval decision. The new clean energy package also provides the process for amendment of the network codes in Article 56. The following box provides Article 56 as proposed by the European Commission. At the conclusion of the trilateral contract, this may be modified.

Article 56¹⁰¹	
Amendments of network codes	
1.	The Commission is empowered to amend the network codes within the areas listed in Article 55(1) and Article 55(1a) and following the respective procedure under Article 55. Amendments can also be proposed by the Agency under the procedure set out in paragraphs 2 to 3 of this Article.
2.	Draft amendments to any network code adopted under Article 55 may be proposed to the Agency by persons who are likely to have an interest in that network code, including the ENTSO for Electricity, the EU DSO entity, regulatory authorities, distribution and transmission system operators, system users and consumers. The Agency may also propose amendments on its own initiative.
3.	The Agency may make reasoned proposals for amendments to the Commission, explaining how such proposals are consistent with the objectives of the network codes set out in Article 55(2). Where it deems an amendment proposal admissible and on amendments on its own initiative, the Agency shall consult all stakeholders in accordance with Article 15 [recast of Regulation (EC) No 713/2009 as proposed by COM(2016) 863/2].
4.	The Commission is empowered to adopt, taking account of the Agency's proposals, amendments to any network code adopted under Article 55 as delegated acts in accordance with Article 63.
6.	Consideration of proposed amendments under the procedure set out in Article 63 shall be limited to consideration of the aspects related to the proposed amendment. Those proposed amendments are without prejudice to other amendments which the Commission may propose.

¹⁰¹ Includes amended after the last trilateral dialogue published in European Council, (2019)

9.3 ANALYTICAL FRAMEWORK

This section provides an analytical framework that consists of six dimensions. The dimensions are imbalance settlement rule, imbalance settlement period, product and service definitions, scarcity pricing, intraday market and integrated balancing market. In this chapter, we present these six dimensions¹⁰².

9.3.1 IMBALANCE SETTLEMENT RULE

Article 2(9) of the EB GL (European Commission, 2017b) defines imbalance settlement as “*a financial settlement mechanism for charging or paying balance responsible parties for their imbalances*”. Van der Veen et al., (2012) further describe imbalance settlement as follows: “*In the imbalance settlement process, which takes place after real-time, both the schedule deviations of BRPs and the imbalance prices are determined. The schedule deviation, or imbalance volume, of a BRP is the difference between the planned net electrical energy exchange with the power grid over its entire energy portfolio (as specified in the energy schedule) and the actual net electrical energy exchange, which is measured in real-time.*” In theory, the cost of balancing the system should be allocated to the imbalanced BRPs. Thus, the choice of imbalance settlement rule becomes a critical design parameter to ensure efficient and accurate allocation of balancing costs.

Article 2(12) of the EB GL defines imbalance price as “*the price, be it positive, zero or negative, in each imbalance settlement period for an imbalance in each direction*”. The two approaches have been widely discussed in the literature; Brijs et al., (2017); Fernandes et al., (2016); Newbery, (2006); Neuhoff et al., (2015), Meeus and Schittekatte, (2018) amongst others provide an overview.

Broadly, imbalances can be settled either by dual imbalance pricing or single imbalance pricing. In dual pricing methodology, different prices are set for positive and negative imbalances (Pérez-Arriaga (p378), 2013). According to Neuhoff et al., (2015), “*a higher price is charged for market participants that are short of power in real time than is offered to market participants that are long in the same instance*” Thus incentivizing the BRPs to balance their positions accurately. However, there is a risk of discrimination against smaller parties, as large players can net their imbalance and thus reduce costs which may cause them to “outsource” their balancing requirements (Vandezande et al., 2010). On the contrary, in a single pricing mechanism, the BRPs with positive as well as negative imbalances are exposed to the same price (Van der Veen et al., 2010). In a single price mechanism, the BRP has the incentive for ensuring accurate balancing of their position from the higher volatility that would occur close to real-time due to fewer assets available to balance the system at short notice (Neuhoff et al., 2015). Thus there is no need to pool resources and size-based discrimination can be avoided (Neuhoff et al., 2015; Vandezande et al., 2010).

In the EU, Art. 52(2) of the EB GL indicates a push towards harmonisation. It states that single pricing should be applied. However, a Transmission System Operator (TSO) may propose to the National Regulatory Authority (NRA) to apply dual pricing under certain conditions and with the necessary justification. ENTSO-E, (2018c) discusses five such conditions as follows. 1) Dual pricing as a mitigation measure for power oscillations in specific

¹⁰² ENTSO-E, (2018a) provides an overview of balancing market design parameters across Europe

ISPs. 2) Where problems in system operation are foreseen, because system imbalance does not indicate a clear incentive in individual ISPs. 3) For all ISPs, if the costs of balancing energy used to balance the system and other costs related to balancing with the exception of balancing capacity costs are to be covered by BRPs causing the imbalances. 4) Asymmetric application of price components. 5) For central dispatching model for all ISPs where the application of single imbalance pricing does not provide correct incentives to scheduling units to respect the unit commitment and dispatch instructions issued by a TSO within the integrated scheduling process in order to ensure a secure system operation.

9.3.2 IMBALANCE SETTLEMENT PERIOD

Article 2(10) of the EB GL (European Commission, 2017b) defines imbalance settlement period (ISP) as “*the time unit for which balance responsible parties’ imbalance is calculated*”. The length of the ISP itself is an important parameter. A shorter ISP more correctly allocates the cost of balancing, i.e. it is possible to reflect the costs of fast-changing flexible balancing actions better. Also, a shorter ISP helps the TSO to control the system balance easier; this is of particular importance with more volatile generation and consumption. However, the longer the ISP, the more the imbalance volume is limited for the BRP as short-term fluctuations of the BRPs’ imbalances are netted out.

In Art. 53, the EB GL (European Commission, 2017b) states that within three years after the entry into force (18 December 2020), all TSOs shall apply the imbalance settlement period of 15 minutes. An exemption is possible per synchronous area if the TSO of that synchronous area can justify an alternative duration and the NRAs approve this exemption. Alternatively, also all NRAs of a synchronous area can apply for an exemption at their initiative. In both cases, it needs to be shown every three years to ACER that the benefits of having an unharmonized ISP outweigh the costs.

9.3.3 PRODUCT AND SERVICE DEFINITIONS

Product and service definitions are a crucial element for ensuring the efficient functioning of any market and provide a level playing field for all market participants. In the context of intermittent Renewable Energy Sources (RES), the rules must be designed to eliminate or at least minimise any barrier for their entry into the balancing market. Samuelson and Nordhaus, (2010) describe barriers to entry as “*factors that make it hard for new firms to enter an industry*”.

Art. 25(4) of the EB GL provides a list of characteristics for standard products in the balancing capacity (and energy) market. Some key balancing product characteristics from an intermittent renewables perspective and especially offshore wind are the following¹⁰³:

Minimum bid size: The minimum capacity that is allowed to be (single) bid on the balancing market. In the Day Ahead Market (DAM) and Intraday Market (IDM) this parameter is not considered restricting as it is set low enough

¹⁰³ Note that this list is not-exhaustive.

(Agora, 2016). However, in balancing markets, limits are often a lot higher, e.g. for a Frequency Restoration Reserve (FRR), the minimum bid size ranged from more than 5 MW in Norway to 1 MW in Belgium in 2016. A lower minimum bid size reduces the entry barriers for new players in the balancing market (Borggreve and Neuhoff, 2011). It should be noted that higher minimum volume requirements can be compensated provided that aggregation is permitted.

Contract period: The specified period for which the BSP is obliged to offer (a specific volume of) balancing energy during a specified period if a BSP's balancing capacity offer is accepted. The contract period can vary from a year to a couple of hours. Other variations too are possible — for example, a balancing capacity contract with the BSP for offering balancing capacity at peak hours for a particular week. Thus, the ability of the resource to be available for the contracted period becomes an important parameter. Therefore, the contract period influences the extent to which variable RES, storage and demand response can participate in the balancing capacity market.

Product symmetry: Upward and downward balancing capacity/energy can be procured jointly, called 'symmetric balancing products', or separately, called 'asymmetric balancing products'. Art. 32(3) of the EB GL requires that the procurement of upward and downward balancing capacity for at least FRR and Replacement Reserve (RR) shall be carried out separately. However, each TSO may submit a proposal to the regulatory authority for a temporary exemption to this rule. Any such proposal shall include an economic justification. The EC proposal for the Regulation on the internal market for electricity tends to go one step further by stating in Art. 5(9) that 'the procurement of upward balancing capacity and downward balancing capacity shall be carried out separately'. It is assumed that this means that the balancing capacity for all reserve types, including Frequency Containment Reserve (FCR), should be procured asymmetrically without exceptions. The separation of upward and downward balancing procurement can reduce entry barriers for a player that may be able to offer balancing capacity/energy in only one direction. This makes it relevant from the offshore wind perspective.

Time-lag: The lag between the gate closure of the balancing capacity market and the start of the contract period in which balancing energy should be offered to the balancing energy market. The time-lag can vary from a day to months and may differ by type of reserve. The time lag impacts the ease of the market parties to estimate their opportunity cost. The closer to real-time, the better forecasts become, and this improves the TSO's estimate of its reserve needs. Regarding timing, the EB GL states in Art. 24 that the balancing energy gate closure time should not be before the intraday cross-zonal gate closure time and as close as possible to real-time.

9.3.4 SCARCITY PRICING

The concept of scarcity pricing in balancing markets is understood from two observations from Figure 45.





Figure 45: Overall costs of balancing (capacity and energy) and imbalance prices over national electricity demand in a selection of European markets in 2016 (ACER and CEER, 2017)¹⁰⁴

It is observed from Figure 45 that balancing capacity costs significantly outweigh the balancing energy costs for almost all Member States. This indicates that more money is spent on reserving capacity ('the insurance') than on the actual delivery of energy. Furthermore, in most cases, solely the balancing energy price determines the imbalance price for the unbalanced BRPs (van der Veen and Hakvoort, 2016). Thus, the full cost of balancing is not reflected in the imbalance settlement¹⁰⁵. This makes a case for introducing a 'scarcity price' to reflect reservation cost when the available reserves are scarce, and the system could be at risk. Consequently, scarcity prices can aid in recuperating the full balancing cost from those who cause these costs instead of socialising the missing money overall grid users.

This idea is already implemented in some form in parts of the United States (US) under the name of Operating Reserve Demand Curve (ORDC), see, e.g. Hogan (2005) and Levin and Botterud (2015), and under the name Reserve Scarcity Pricing (RSP) in Great Britain (Ofgem, 2015). Papavasiliou and Smeers (2017) analyse in their work the implementation of a similar idea in the Belgian power system. Furthermore, BRPs will be incentivised to be balanced at moments of system stress. As is the case in the US, both the imbalance prices and the balancing energy prices rise at moments of system stress. In that case, then the BSP too would have an incentive to be available at the moments when they are needed the most.

Art. 44(3) of the EB GL states that: *'Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity, administrative costs and other costs related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If*

¹⁰⁴ Imbalance charges applied in the Nordic market are not included in the figure as data were not available for all Nordic countries. The procurement costs of reserves reported by the Polish TSO comprise only a share of the overall costs of reserves in the Polish electricity system.

¹⁰⁵ According to van der Veen and Hakvoort, (2016) balancing capacity costs "are usually allocated to all system users through adaptation of the system services tariff. Alternatives are an additional price component in the imbalance price, a separate fee structure for BRPs, and the assignment of reserve obligations to market participants."

*TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority.*¹⁰⁶

9.3.5 INTRADAY MARKET

Battle (2013) describes intraday markets as “*adjustment markets (so-called intraday markets) where additional trading can take place when supply or demand situations change with respect to the estimates cleared on the day-ahead market*”. A vital parameter prerequisite for being able to control one’s imbalance volume is the possibility to trade in a liquid intraday market. If the intraday market does not function well, BRPs will not be able to hedge themselves against real-time imbalances sufficiently. Thus, the functioning of the intraday market and the total balancing needs for a system are interrelated. The interaction between the balancing market and the intraday market is also discussed by Weber (2010).

Furthermore, product design of the intraday market matters, namely it is essential that the products traded in the intraday should have at least the same temporal granularity as the ISP. For instance, if the granularity of the products in the DAM and IDM were one hour while the ISP is 15 minutes, it will become costlier for market participants to hedge a crucial 15 minutes as they will have to buy or sell a full hour block of energy to do so. The EC proposal for the Regulation on the internal market for electricity states in Art. 7(2) that “*market operators shall provide market participants with the opportunity to trade in energy in time intervals at least as short as the imbalance settlement period in both day-ahead and intraday markets.*”

The intraday gate-closure time is another critical parameter. The closer to real-time the intraday gate closure takes place, the better the final forecast for generation and consumption. The intraday gate closure time is a trade-off. On the one hand, trading in the intraday market as close as possible to real-time maximises market participants’ opportunities for adjusting their balances. On the other hand, according to ENTSO-E, (2018), a longer time frame is useful for “*providing TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security*”. Art. 59(3) of CACM GL states that the intraday cross-zonal gate closure shall be at most one hour before the start of the relevant market time unit. Note that the gate closure for intraday trade within a bidding zone can be different from the intraday cross-zonal gate closure time.

9.3.6 INTEGRATED BALANCING MARKET

Currently, balancing mechanisms are mostly organised at a national level. One of the main objectives of the EB GL is to harmonise and integrate balancing markets. Several studies have indicated the benefits of harmonising and integrating balancing markets. Baldursson et al. (2018) and Van den Bergh et al. (2018) are examples of recent quantitative studies on this topic. Their assessments conclude that significant welfare gains can be realised from such integration. Baldursson et al. (2018) present a stylised model of cross-border balancing. The authors conclude that “*Based on actual market data of reserves procurement of positive and negative automatic frequency*

¹⁰⁶ EBGL (Art. 30(1.a)) states that the balancing energy market should be based on marginal pricing. However, if all TSOs identify inefficiencies in the application of marginal pricing, they may request an amendment and propose an alternative pricing method (Art. 30(5)).

restoration reserves in Belgium, France, Germany, the Netherlands, Portugal and Spain, we estimate the procurement cost decrease of exchange to be €160 million per year and of sharing to be €500 million per year.” Van den Bergh et al. (2018) use a unit commitment model to study “the impact of cross-border reserve markets on system generation costs and system reliability, for a case study of the Central Western European electricity system. More, in particular, the implementation of network constraints in cross-border reserve procurement” in a scenario for central western Europe. The authors conclude that cross-border reserve market would lead to cost efficiency gains as well as significant savings in operating costs. Artelys et al.’s (2016) study conducted on behalf of the European Commission provided a quantitative as well as qualitative assessment. The quantitative assessment supported the conclusion of welfare gains from integration, while the qualitative assessment identified identify four key benefits of balancing market integration.

- Lower volumes of balancing action and reserve capacity would be required due to the netting of imbalances and ‘risk pooling’ across markets.
- Improvements in allocative efficiency can be achieved by “allocating the balancing services required more cost-effectively across the pool of potential Balancing Service Providers, thereby reducing total costs”.
- Merging of markets would enhance competitions, as the existence of more BSPs would increase “the competitive pressure to maintain low prices, thereby minimising consumer costs and encouraging efficient decisions on system operation”.
- The study indicates a positive implication for the market accessibility of RES and Demand Response through a standardisation of the product definition and procurement processes.

9.4 DISCUSSION

In this section, we assess the six dimensions from Chapter 2 from the three perspectives of the Offshore Wind Farm (OWF) as a BRP, the OWF as a BSP and the overall system.

9.4.1 IMBALANCE SETTLEMENT RULES

Imagine a market party with random, uncontrollable imbalances fluctuating around zero, which are entirely uncorrelated with the system imbalance and the system imbalance also being random and fluctuating around zero. In that case, under single pricing¹⁰⁷ (where imbalance prices are equivalent to the marginal procurement price for these balancing services), the total imbalance cost of that BRP will net out thus in theory to a “zero-sum game” for the TSO (Vandezande et al., 2010). Under a dual price regime, average procurement costs are generally used to settle BRPs with imbalance contributing to the system imbalance while settlement of BRPs that have imbalances counteracting the system imbalance are settled based on wholesale price indicators (such as power exchange price) (Vandezande et al., 2010). Vandezande et al., (2010) explain the impact as follows: “Given the presence of power exchange prices (and possibly penalties – cf. below), a two-price system no longer implies a zero-sum game for the TSO, which should not have financial interest in the imbalance settlement. Accordingly, insofar the difference is not used by the TSO to cover other costs in real time (e.g. staffing

¹⁰⁷

and IT costs), it should result in a reduction of transmission tariffs. But even if this is done, it still entails a transfer of money from inflexible users – such as wind generators – to average users.” Furthermore, single pricing can create a revenue opportunity for BRPs as they could engage in passive balancing, i.e. having an imbalance in the opposite direction of the system imbalance. Plus, with single pricing, the true cost and value are reflected in ones’ action in real-time, which is expected to lead to a more optimal allocation of resources and higher system efficiency. Therefore, the use of a single pricing rule for imbalance settlement can be considered as the preferred design from all three perspectives. However, note that in some specific cases dual price can be useful from a system operator’s perspective.

The EB GL imposes single pricing to be used and only exceptionally allows dual pricing. Therefore, it can be considered that the current regulation on imbalance settlement agrees with the desired configuration.

9.4.2 IMBALANCE SETTLEMENT PERIOD

In contrast to the imbalance settlement rules, the preferred choice of imbalance settlement period is not aligned from the user and service provider perspective in the offshore wind context. From the standpoint of offshore wind generation as a BRP, a longer imbalance settlement period would be desirable. A longer imbalance settlement period would provide these BRPs more possibility of netting out their imbalances thus lowering the final imbalance settlement cost to be paid.

On the other hand, a shorter imbalance settlement period would be beneficial for an offshore wind generator that is a BSP. A shorter imbalance settlement period would mean that the BSP would require to provide the promised quantity of balancing energy consistently over a shorter period thus reducing the risk that arises from intermittency of these resources. Consequently, it would increase ease of scheduling the provision of balancing energy for intermittent resources such as offshore wind¹⁰⁸. Please note that this is only true if the balancing time unit, the period over which the balancing price changes and the ISP are the same, which is mostly the case.

A shorter imbalance settlement period of balancing prices will also make it easier to reflect the value of flexibility, as the cost of balancing can be allocated more accurately. Lastly, Fernandes et al., (2016) explain that with longer ISPs the likelihood of both upward and downward reserve activation within one ISP increases, which makes it very hard to signal correct imbalance prices to BSPs. Shorter imbalance settlement periods make it easier for passive balancing, helping the system by being imbalanced in the direction opposite of the system imbalance. In conclusion, it can be assumed that a shorter imbalance settlement period is more cost efficient from a system point of view. The EB GL and the CEP (EC proposal for the Regulation on the IME) foresee a convergence towards an imbalance settlement period of 15 minutes, which is shorter than what is in place in some countries today. According to the European Council, (2018) (proposed Article 7(4)): *“By 1 January 2021, the imbalance settlement period shall be 15 minutes in all scheduling areas unless regulatory authorities have granted a derogation or an exemption. Derogations may only be granted until 1 January 2025. When an exemption has*

¹⁰⁸ In that case it is assumed that the length of the imbalance settlement period and the granularity of products in the balancing energy markets are the same.

been granted, by all national regulatory authorities of a synchronous area, the imbalance settlement period shall be no greater than 30 minutes by 2025.”

9.4.3 PRODUCT AND SERVICE DEFINITIONS

Product and service definitions are relevant only from a BSP perspective and a system perspective. Although relevant, are not directly affected by these rules do not directly affect BRPs (or demand). Therefore, we assess this element only from the BSP and system perspectives.

The product and service definitions should be set such that they eliminate the barrier for entry for offshore wind. Hirth and Ziegenhagen, (2015) discuss that having smaller bid sizes and short contract periods reduce forecast errors and thus are crucial for reducing entry barriers for intermittent renewable generators to participate in the balancing market. Furthermore, they also discuss that it is desirable that the balancing energy gate closure is as close to real-time as possible.

Finally, an offshore wind park can offer downward balancing capacity with relative ease by curtailing part of its production. However, it cannot as easily provide upward balancing. To be able to provide upward balancing, the turbines would have to operate continually below maximum thus missing out of electricity generation at near zero marginal cost. Therefore, from the perspective of an offshore wind farm that is a service provider, an asymmetric balancing product would be desirable.

From a system perspective, the product and service definitions should be set such that entry barriers are eliminated, and a level playing field is provided for all participants. Thus, it may be said that design choices discussed for OWFs as BSPs can also be considered relevant at a system level. Furthermore, these product and service definitions are applicable not just for OWFs but also for encouraging other types of flexibility such as demand participation (Böttger et al., 2015) and Distributed Energy Resources (Meeus and Schittekatte, 2018a).

However, possible trade-offs can exist between integrating new (smaller) players in the balancing market, system cost-efficiency (coordination costs, transaction costs etc.) and system security. Therefore, an analysis to find the best compromise at a system level is recommended. A cost-benefit analysis (CBA) is one such alternative for conducting this analysis.

The product and service definitions for balancing mechanisms in the European Union (EU) vary significantly (Brijs et al., 2017) and entry barriers for offshore wind farms to become service providers exist. However, one of the objectives of the EB GL is to give access to all market participants to the balancing market, be it individual or through aggregation. For example, in recital 8 of the EB GL it is stated that *‘the rules concerning the terms and conditions related to balancing set out the principles and roles by which the balancing activities governed by this Regulation will take place, and ensure adequate competition based on a level-playing field between market participants, including demand-response aggregators and assets located at the distribution level.’*

9.4.4 SCARCITY PRICING

Scarcity pricing can be a way to reward OWF service providers to be available when the system is really under stress. Especially for flexible service providers, the implementation of scarcity prices will be welcomed as their services can be valued more. OWFs can be considered relatively flexible, especially when providing downward balancing. Therefore, the introduction of scarcity pricing can be considered to have a positive impact on them.

From an OWF user perspective, scarcity pricing could be considered as an added risk due to the possibility of undesirable price spikes occurring. This is mainly a concern when the opportunity for a wind farm operator to be flexible is limited. For instance, the ability of a wind farm to increase its generation is limited by wind availability. Thus, being imbalanced at a moment when the system is at risk could lead to high balancing costs.

From a system perspective, scarcity pricing could allow for more competition in the provision of balancing energy and possibly could lead to lower costs for the reservation of balancing capacity. Furthermore, the greater incentive would be available for flexible resources to participate in the balancing mechanisms. The current regulation makes it possible to apply scarcity pricing. The EB GL allows the TSO to develop a proposal for such additional settlement mechanism in Art. 44(3).

9.4.5 INTRADAY MARKET

A well-functioning intraday market would reduce the total system imbalance and imbalance prices are expected to be lower. If there are ample trading opportunities in the intraday market and the intraday gate closure is near to real-time, balance responsible market players can trade out their imbalances with greater ease. This is especially true with a high penetration of variable RES of which the uncertainty in production significantly reduces closer to real-time (Karanfil and Li, 2017). Therefore, a liquid and the well-functioning intraday market can be perceived positively from a BRP as well as from a system perspective. Furthermore, a liquid intraday market can provide alternative trading opportunities for service providers besides offering its services in the balancing market. The need for liquidity in the intraday market for integration of wind power is discussed by Weber, (2010).

Borggreffe and Neuhoff, (2011) assess market design in several European countries for their ability to enable the participation of wind technologies. The authors conclude that *“The EU has made some progress towards integrating power markets, but today’s intraday and balancing market designs are far from a fully efficient and harmonised market.”* This is, however, changing rapidly. In a recent paper, Ocker and Ehrhart (2017) argue that the introduction of an intraday auction with 15-minute products in Germany in 2014 helped to allow more precise scheduling of variable RES and other generation technologies and led to a significant reduction in overall balancing costs.



9.4.6 INTEGRATING BALANCING MARKETS

Better-integrated balancing markets will lower the total costs for the imbalances of a balance responsible as discussed by Artelys et al. (2016) and explained in the earlier section. Thus, balancing market integration can be viewed as desirable from a user perspective. From the standpoint of a BSP, balancing market integration would also mean that the BSP might face more competition from cross-zonal BSPs. However, at the same time, the integration of balancing markets will also enhance the trading opportunities for these players in the balancing markets.

Furthermore, an integrated market would reduce entry barriers for OWF-BSPs. Overall, from a system perspective, market integration would lead to welfare gains for the system by lowering costs (Artelys et al., 2016; ERGEG, 2009; EURELECTRIC, 2008; KULeuven and Tractabel, 2009; van der Veen et al., 2010). Artelys et al. (2016). In their position paper on this topic, ENTSO-E, (2011) state that *“Effective cross-border balancing markets in addition to a day ahead and intraday energy markets provide the tools to facilitate the cost effective procurement of short term balancing services. This can potentially reduce the system balancing costs and facilitate the integration of variable RES units into the electricity system.”* Therefore, from a system perspective, greater integration of balancing market is a desirable outcome.

9.5 CONCLUSIONS & RECOMMENDATIONS

This research assesses the balancing mechanisms from the perspective of offshore wind technologies participation. This analysis combines six dimensions with three perspectives. In this section, we highlight the key conclusions from this research.

- **Imbalance settlement rule:** a single price rule for imbalance settlement is the best solution from all perspectives. The EB GL also supports this view.
- **Imbalance settlement period:** a conflict between the user and service provider perspective occurs. The EB GL foresees a convergence to an imbalance settlement period of 15 minutes with possibility of temporary exemption.
- **Product and service definitions:** These rules are relevant only from a system perspective and a balancing service provider perspective. The product and service definitions should be set that they eliminate the barrier for entry for OWF. Smaller bid sizes and contract periods, a gate closure which is as close to real time as possible, and use of asymmetric balancing products are some key desirable elements of a market design suitable for offshore wind participation. However, some trade-offs may be required while selecting design parameters.
- **Scarcity pricing:** Scarcity pricing is desirable from a system point of view, i.e. the total cost may reduce due to the possibility of attracting more market players and thus more competition. A balancing service provider too would benefit from the better valuation of its services. From a balance responsible party perspective,

scarcity pricing could be considered as an added risk due to the possible occurrence of undesirable price spikes.

- **Intraday market:** a well-functioning liquid intraday market with a gate-closure as close to real-time as possible would be beneficial from all three perspectives.
- **Integrating balancing market:** greater integration of balancing markets would be desirable. However, the current market design needs to evolve further for effective realisation of the benefits from integration of balancing markets.

Table 27 provides a summary of six selected balancing mechanism concepts from the three perspectives.

Table 27: Summary of the current balancing mechanisms regulation from the three perspectives.

Dimensions	Perspectives		
	System	OWF BSP	OWF BRP
Settlement rule	Single pricing	Single pricing	Single pricing
Imbalance settlement period	Short	Short	Long
Product and service definitions	Costs and benefits of removing entry barriers need to be assessed.	Following rules are desirable to reduce entry barriers: - Smaller bid sizes - Smaller contract period, - Close to real-time gate closure	Indirectly affected
Scarcity pricing	Desirable (lower costs)	Desirable (Incentive to participate)	Undesirable (Risk of price spikes, but benefit if costs reduce)
Intraday market	Desirable (lower costs)	Desirable (Another trading opportunity)	Desirable (Lower costs)
Integrating balancing markets	Desirable (lower cost)	Desirable (Greater market liquidity)	Desirable (Lower costs)

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11 ANNEXES

11.1 ANNEX I: ENTSOG'S CBA FOR GAS PROJECTS AND JRC'S CBA FOR SMART GRIDS

11.1.1 INTRODUCTION OF THE METHODOLOGIES

CBA for gas projects by ENTSOG

ENTSOG also had the task of developing a CBA methodology for Energy System-wide analysis to support the PCI selection process. Equivalently with the CBA for electricity infrastructure not only gas pipelines but also gas storage projects are assessed with this methodology. The ENTSOG methodology was, just as the ENTSO-E methodology, finally approved by the EC in February 2015.

Similarly to electricity infrastructure, the development of cross-border gas infrastructure projects¹⁰⁹ is deemed crucial to achieving the Union's energy and climate policy objectives. Access to sufficiently diversified gas supplies and stronger infrastructure connectivity are presented as two main pillars of Europe's future gas strategy.¹¹⁰ Although the long-term role of gas is uncertain, it is generally accepted that gas will play an important role in the transition phase between where we are now and the future almost fully electrified/decarbonized energy system supported by renewable electricity generation. Considering that only about one-third of the EU's gas consumption is produced domestically, and the dominant share is imported from mainly Russia, Norway and North-Africa¹¹¹ there is an obvious need for sufficient cross-border gas infrastructure connecting these production areas with the different consumption centres in the EU to ensure an efficient and secure gas supply.

CBA for smart grids by JRC

Due to the strong penetration of distributed energy resources installed at distribution level, a passive distribution network optimised to handle unidirectional flows is no longer adequate. Instead, innovative grid technologies, relying on significant advancements in ICT during the last decades, are attracting more and more attention. Investments in these so-called smart grids tend to be challenging for two reasons. Firstly, the technologies are still relatively immature, implying that the technical feasibility and financial viability are hard to assess. And secondly, smart grid investments are dispersed with local conditions having a strong impact. It is hard to generalise experience from small-scale demonstrations in different jurisdictions and led by different agents.

The European Commission's Joint Research Centre (JRC) made the first effort to propose comprehensive guidelines for assessing Smart Grid projects with CBA¹¹². The report consists of a theoretical guiding framework

¹⁰⁹Gas infrastructure includes pipelines and compressor projects as well as lng terminals and storage projects that have a regional impact.

¹¹⁰IEA, 2015, Medium-Term Market Report: Market Analysis and Forecasts to 2020

¹¹¹Tagliapietra, S. and Zachmann, G., 2016. Rethinking the security of the European Union's gas supply. A Bruegel policy recommendation

¹¹² Giordano, V., Onyeji, I., Fulli, G., Sánchez-Jiménez, M., Filiou, C., 2012. Guidelines for conducting a cost benefit analysis of smart grid projects. JRC reference reports. doi: 10.2790/45979.

and a case study to illustrate its use. It is important to mention that this CBA methodology was also used as a basis for discussion in the 2012 work program of the EC Smart Grid Task Force for the definition of eligibility criteria for Smart Grid PCIs.

11.1.2 ASSESSMENT

CBA for gas projects by ENTSOG

Applying the checklist to the ENTSOG methodology for the CBA of gas infrastructure projects we find three shortcomings in common with the sister ENTSO-E methodology. The ENTSOG CBA approach for taking project interaction into account, however, is conforming better to the FSR recommendation. It remains to be seen which direction a possible ENTSOG CBA 2.0 would take.

1 concern regarding the input

Contrary to the ENTSO-E methodology for CBA of electricity transmission infrastructure, the ENTSOG CBA methodology for gas infrastructure tries to track down potentially competing projects by evaluating projects against baselines that include (cf. ENTSO-E's TOOT) and exclude (cf. ENTSO-E's PINT) the other candidate projects. On this point, it is more advanced than the ENTSO-E CBA methodology for infrastructure projects.

Similarly to the ENTSO-E methodology, the ENTSOG CBA methodology is unclear about the disaggregated reporting of infrastructure cost components. Several cost categories are mentioned, but if only a global cost is reported it will be impossible to benchmark these costs against typical unit costs as reported in the ACER recommendation.

2 concerns regarding the output

Our concerns regarding the output of the CBA of gas infrastructure projects are the same as those we raised above for the ENTSO-E method. First, it is not clear whether all benefits are reported in a disaggregated format that allows scrutinising the regional distribution of the benefits. Second, ENTSOG also relies on MCA which provides a less transparent way of ranking the projects than monetizing as much as possible the potential benefits and then ranking the projects according to their net present value.

CBA for smart grids by JRC

Applying the checklist to the JRC methodology for the CBA of smart grid projects, we find shortcomings in eight out of the ten areas of the FSR framework. Considering that the method was the first to be designed, it has the merit of having offered a structured overview of issues to be taken into account in a cost-benefit analysis of an infrastructure project. However, the JRC method has not progressed since that first step, and consequently, it does not offer a common methodology for evaluating smart grid projects. This is worrisome as the penetration of distributed energy resources at the distribution level is rising, and the number of smart grid demonstration projects is increasing. Even though the dispersed nature of these projects and the involvement of a great many economic agents in different jurisdictions make their comparison challenging, these projects need nevertheless to be evaluated and compared to draw lessons for replication and upscaling purposes.



3 concerns regarding the input

The JRC smart grid methodology does not consider project interaction because there is no common baseline. Project promoters are encouraged to use a baseline tailored to local conditions. As such no positive or negative synergies between different projects can be discovered. Also, no recommendation to align the data collection for the CBA with existing data collection processes is done, for which the other infrastructure methodologies rely on their respective TYNDP processes. Instead, a local data collection process is recommended, which does not ensure consistency between CBAs conducted for different projects. At last, as for the other CBA methodologies presented, no recommendations are provided with regard to the disaggregated reporting of costs items.

3 concerns regarding the calculation

It is best practice to focus on a limited list of effects that are significant for all projects and to monetize those with the possibility for supplementary analysis on other benefits in justified cases. The JRC method, however, provides a non-exhaustive list of possible effects including more than 20 effects that can be monetized, and over 50 key performance indicators that could be qualitatively assessed. Not reducing and harmonising this list of effect renders it extremely difficult to compare the outcome of a CBA for different projects that consider different effects. Second, the smart grid method does neither provide nor recommend the use of a common model or to explicitly state the used model. Third, in contrast with the other CBA methodologies, no common discount factor has been proposed.

2 concerns regarding the output

In addition to the concerns raised about the input to the CBA and the calculation of the net benefit, the JRC method is also not conforming to the best practices regarding the output of CBA. The methodology is not clear on the disaggregated reporting of the different benefits. Furthermore, the use of MCA is recommended to make the final assessment of a project. Considering that there is no common data collection and no common method for calculating the benefits, it is unlikely that the MCA results of different projects can be compared.

11.1.3 CONCLUDING TABLE

Table 28: Overview of the application of the FSR framework for a robust CBA on four methodologies in the EU energy context

Status of implementation	ENTSO-e 1.0 & 2.0	ENTSO-g	Smart Grid	Balancing
INPUT (1) Project interaction must be taken into account in the project and baseline definition	Multiple TOOT	Two baselines	No common baseline	Not applicable
INPUT (2) Data consistency and quality should be ensured	TYNDP	TYNDP	No common data gathering process	TYNDP
INPUT (3) Costs should be reported in disaggregated form	Not clear	Not clear	Not clear	Unclear
CALCULATION (4) CBA should concentrate on a reduced list of effects	Reduced list	Reduced list	50 KPI + 22 EPRI effects + other qualitative	Reduced list
CALCULATION (5) Distributional concerns should not be addressed in the calculation of net benefits	OK	OK	OK	OK
CALCULATION (6) The model used to monetise the production cost savings and gross consumer surplus needs to be explicitly stated	Explicit model available	Explicit model available	No common model	Explicit model available
CALCULATION (7) A common discount factor should be used for all projects	4% for all	4% for all	No common discount rate	Uniform; aligned with TYNDP & PCI; regularly updated
CALCULATION (8) A stochastic approach/scenario analysis should be used to address uncertainty	OK	OK	OK	OK
OUTPUT (9) Benefits should be reported in disaggregated form	Not clear	Not clear	Not clear	Regional and country effects should be reported
OUTPUT (10) Ranking should be based on monetization	MCA	MCA	MCA	Monetized ranking

11.2 ANNEX II: EX-POST CBA OF THE OFTO REGIME

The purpose of this annex is to introduce the UK OFTO regime and contextualise how the UK regulator approaches offshore transmission assets. This analysis is the result of desk-based research includes a review of ex-post CBAs commissioned by the regulator to assess savings from the tendering process and a discussion with regulatory staff linked to the OFTO regime.

Context: In the UK, offshore wind farm sites are leased by the Crown Estate, which is in charge of the UK seabed. Sites then consent via the Planning Inspectorate under the Department for Communities and Local Government. Thereafter individual projects bid into the UK renewable energy subsidy mechanism, the Contracts for Difference (CfD). Once awarded a CfD with a certain strike price (dependent on the outcome of the auction), projects undergo commissioning and construction of both the generation site and transmission infrastructure. At this stage, OFGEM, the UK regulator, starts the process to sell and license the offshore transmission assets to an independent Offshore Transmission Owner (OFTO). This involves assessing the value of the assets and a tendering process based on a bidding of a project specific revenue stream. Importantly, this differs to the onshore transmission, which is a regional monopoly regime dominated by three entities.

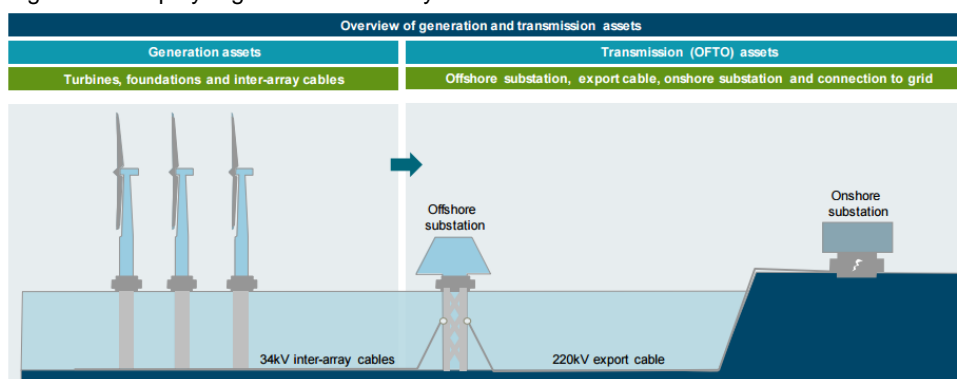


Figure 46: Overview of offshore generation and transmission assets, source: Dong Energy, 2016

CBA Approach: Ofgem does not conduct a CBA of the transmission assets prior to awarding transmission assets to an OFTO. The awarding of CfDs (the generation subsidy) effectively ensures the lowest cost to GB consumers. Instead, specific ‘cost assessments’ are carried out during the OFTO tendering process to calculate the economical and efficient cost of developing and constructing the offshore transmission assets, prior to transferring these over to the OFTO. The UK Government has leaned upon an ex-post CBA to assess the benefits of the 1st three tendering rounds versus a number of counterfactuals.

Interconnector CBAs: Ofgem does assess the costs and benefits of interconnectors. Overall, the process is aligned to the ENTSO-E guidelines. However, it differs in some aspects. For example, it calculates an NPV using a 3.5% discount rate over 25 years and is based on 3 scenarios (as opposed to the 4 TYNDP scenarios), and it is inherently focused on the welfare of GB consumers (as opposed to EU consumers). Aspects examined

include net social welfare (e.g. producer, consumer, and interconnector welfare¹¹³), the impact on wholesale prices, security of supply, emissions, and impact on competition.

Ex-Post Assessment of OFTO Tenders: Two ex-post CBAs have been conducted on the round 1, 2 and 3 tenders. These are:

- Ofgem, Evaluation of OFTO Tender Round 2 and 3 Benefits (2016). Available at: <https://www.ofgem.gov.uk/ofgem-publications/99546>
- CEBA, Evaluation of OFTO Tender Round 1 Benefits (2014). Available at: <https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf>

These CBAs serve to assess the overall cost and benefit of the tendering process versus a set of counterfactuals. The CBA focuses on the cost savings and distribution of these. Specifically, it examines:

- Quantifying cost savings of OFTO projects compared to counterfactuals.
- Identifying where the cost savings originate e.g. from lower allowed operational and financing costs arising from the implemented approach when compared to alternative counterfactual scenarios.
- Identify who may have benefitted from the savings e.g. generators, consumers.

The assessments suggested strong savings to consumers as the result of the approach, and these have increased over the three rounds. Savings are attributed to efficiency, innovation, fall in market rates of return and potential economies of scale from partially fixed operating costs. Savings from the three rounds, which include 13 projects representing 4.4GW of electricity and £2.9bn of investment have been estimated at:

- Round 1: £200m - £400m (9 OFTO licenses).
- Round 2: £326m-£595m (4 OFTO licenses).
- Round 3: £102 – £154m (2 OFTO licenses)

A four-step method was applied. This included:

- Review of the outcomes from the tender rounds
- Calculation of the NPV pricing of the two rounds
- Modelling of the counterfactuals on a like for like basis
- Comparison of the NPV pricing and analysis of the implications

The applied counterfactuals lay out different cost paths under alternative regulatory approaches that could have been implemented instead of the current approach. These are a licensed merchant generation approach and an alternative regulated price control based approaches. These are noted in the table below.

¹¹³ Interconnector welfare, also referred to as congestions rents or auction revenues, is the flow across an interconnector multiplied by the remaining wholesale price differential between the markets after the flow of electricity.

Table 29: Counterfactuals and assumptions applied in the CBA

Element	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
Summary	A licensed merchant approach for the TR1 transmission assets	A variant of the licensed merchant counterfactual	Onshore TO ownership of TR1 assets under price controls	A variant of onshore TO ownership of TR1 assets under price controls	Offshore zonal TO licence for offshore transmission delivery
Description	The generator is responsible for design, build, ownership and operation of the TR1 assets with financing arrangements an entirely commercial relationship internal to the wind farm project	The generation developer designs and constructs the assets, but a sale and leaseback arrangement is introduced for the ownership and the operation of the transmission assets	Onshore TOs have their exclusive onshore transmission licences extended offshore, and offshore services are included within existing onshore price control arrangements	Onshore TOs have their exclusive onshore transmission licences extended offshore, but a dedicated offshore price control is applied to the offshore assets and offshore services	Exclusive multi-zone offshore transmission licences where the TO is licensed (potentially through a competitive tender) for an entire offshore geographical zone and is then obligated to develop any future connections ¹
<i>Counterfactual regimes</i>					
Price controls?	No	No	Yes	Yes	Yes
Price reviews?	No	Potentially	Yes	Yes	Yes
Cost recovery	Through wind farm	Via lease back contract	TNUoS charges	TNUoS charges	TNUoS charges
Form of regulation	Not applicable	Not applicable	Ex-ante	Ex-ante	Ex-ante
Form of regime	Part of wind farm	Lease back terms	Revenue cap	Revenue cap	Revenue cap
Contestability	Potentially	Yes	No	No	Potentially

Source: CEPA analysis

Note 1: the TR1 assets are adopted as operational by a licensee

The applicability of the guidelines versus OFTO tender CBA approach (presented below) reduces significantly given the ex-post nature of the exercise. There is, therefore, the need to better understand the differences and similarities between how ex-post and ex-ante assessments.

Assessment of the CBA approach against set criteria:

1) Project interaction	Project interaction is not applicable as the CBA analysis is an ex-post analysis
2) Data gathering process	Unclear
3) Disaggregated reporting of cost data	Yes; data for individual cost items e.g. financing costs, O&M expenditure, transaction and management (e.g. SPV-related costs)
4) Common list of effects	The CBA examines the trends in revenue streams (TRS), financing costs (e.g. cost of equity and debt), and operating costs. Items such as taxation have been omitted.
5) Disregard distributional concerns	The CBA disregards distributional concerns when assessing the core benefits per tender round. However, it includes the distribution of benefits/costs for the different actors within a separate section. This analysis is yet again made somewhat redundant given the ex-post nature.
6) Explicit algorithms	Yes; the models and assumptions used to quantify counterfactuals, and subsequently cost savings, are outlined. However, models are not provided.
7) Discount rate	Unclear; “use the social time preference rate (STPR) as the real discount rate when evaluating bids” However, actual numbers were not noted.
8) Dealing with uncertainty	The range of 5 counterfactuals adequately contributes to this aspect.
9) Disaggregated reporting of benefits	Yes; financial, operational and bid cost savings reported separately
10) Final Assessment of the project	Yes; options ranked according to (monetary) cost-savings



Additional References consulted:

CEBA / BDO, 2014. Evaluation of OFTO Tender Round 1 Benefits. Available at:
<https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdtr1benefitsassessmentfinalreport.pdf>

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11.3 ANNEX III: ABBREVIATIONS

Sr. no	Abbreviation	Detail
1	ACER	Agency for the Cooperation of Energy Regulators
2	aFRR	Automatic Frequency Restoration Reserves
3	ATS	Autoproducer Transmission Service
4	BRP	Balance-responsible party
5	BSP	Balancing service provider
6	BSUoS	Balancing Services Use of System
7	CAPEX	Capital expenditure
8	CAPM	Capityal asset pricing model
9	CATO	competitively appointed transmission owners
10	CBA	Cost-benefit analysis
11	CBCA	Cross-Border Cost Allocation
12	CC	Connection Charge
13	CEF	Connecting Europe Facility
14	CEP	Clean Energy Package
15	CfD	Contract for differences
16	CoBA	Coordinated Balancing Areas
17	CoD	Cost of debt
18	DAM	Day ahead market
19	DR	Demand Response
20	DTS	Demand Transmission Service
21	EB GL	Electricity Balancing Guideline

22	EC	European Commission
23	EENS	Expected Energy Not Served
24	EEPR	European Energy Program for Recovery
25	EIB	European Investment Bank
26	ENTSO-E	European Network of Transmission System Operators for Electricity
27	ENTSO-G	European Network of Transmission System Operators for Gas
28	EOI	Expression Of Interest
29	EU	European Union
30	EWIC	East-West Interconnector
31	FCP	Frequency containment process
32	FCR	Frequency Containment Reserves
33	FiP	Feed-in premium
34	FiT	Feed-in tariff
35	FRP	Frequency restoration process
36	FRR	Frequency restoration reserves
37	FTE	full-time equivalent
38	GB	Great Britain
39	GCT	Gate closure time
40	GHG	greenhouse gas
41	GTS	Generation Transmission Service
42	ICPR	Incremental cost related pricing
43	IDM	Intraday market
44	IME	Internal market for electricity
45	IQI	Information Quality Incentives
46	ISP	imbalance settlement period
47	ITC	Inter-TSO Compensation Mechanism
48	ITPR	Integrated Transmission Planning Regime
49	LCOE	Levelised cost of electricity
50	MAR	<i>Market to Asset ratio</i>
51	MCA	Multi-criteria analysis
52	mFRR	Manual Frequency Restoration Reserves
53	MOG	meshed offshore grid
54	NC	Network codes
55	NPV	Net present value
56	NRA	National Regulatory Authority
57	NREAP	National renewable energy action plan
58	OFTO	Offshore Transmission Owners
59	OPEX	Operational expenditure
60	ORDC	Operating Reserve Demand Curve
61	OWF	Offshore wind farm
62	PCI	Project of common interest

63	PINT	put-one-in-at-a-time
64	PV	Photovoltaic
65	RAB	Regulatory Asset Base
66	RAV	Regulatory Asset Value
67	RES	Renewable energy sources
68	RIIO	Revenue=Incentives+Innovation+Outputs
69	RO	Renewable Obligation
70	RoE	Return on equity
71	RRP	Reserve replacement process
72	RRP	Replacement reserves
73	RSP	Reserve Scarcity Pricing
74	SO	System Operator
75	SO-GL	System Operation Guidelines
76	SoS	Security of supply
77	TEN-E	EU Trans-European Network Energy
78	TEP	transmission expansion planning
79	TNUoS	Transmission Network Use of System
80	TO	Transmission Operator
81	TOOT	take-one-out-at-a-time
82	TSO	Transmission system operator
83	TYNDP	Ten-Year Network Development Plan
84	UK	United Kingdom
85	UoS	Use of the System Charges
86	VOLL	Value of loss load
87	WACC	weighted average cost of capital